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PROCEEDINGS, COAL COMBUSTION SEMINAR, JUNE 19-20, 1973, RESEARCH TRIANGLE PARK, N. C. 27711

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ENVIRONMENTAL PROTECTION TECHNOLOGY SERIES

PROCEEDINGS, COAL COMBUSTION SEMINAR,
JUNE 19-20, 1973
RESEARCH TRIANGLE PARK, N.C. 27711

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PROCEEDINGS, COAL COMBUSTION SEMINAR, JUNE 19-20, 1973 RESEARCH TRIANGLE PARK, N.C. 27711

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&
David W. Pershing, Vice Chairman

Environmental Protection Agency
National Environmental Research Center - Research Triangle Park,
Control Systems Laboratory,
Combustion Research Section

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PREFACE

The Coal Combustion Seminar was held June 19-20, 1973 in the auditorium of the National Environmental Research Center, Research Triangle Park, North Carolina and was sponsored by the U. S. Environmental Protection Agency, Office of Research and Development, Control Systems Laboratory, Combustion Research Section.

The Seminar, under the chairmanship and vice-chairmanship of Messrs. Robert E. Hall and David W. Pershing, began Tuesday morning. The official welcome and introduction were given by Dr. E. E. Berkau, Chief, Combustion Research Section.

The Seminar consisted of four sessions divided into two main areas: fundamental research, and pilot and full scale tests.

Sessions 1 and 2, chaired by Robert E. Hall and G. Blair Martin, respectively, were concerned with fundamental research. David W. Pershing and David G. Lachapelle were chairmen for Sessions 3 and 4, respectively, which dealt with pilot and full scale tests.

A tour of the Combustion Research Section's laboratory was given on Wednesday afternoon by John H. Wasser, G. Blair Martin, David W. Pershing, and David G. Lachapelle.

All papers presented during the Seminar are included in these proceedings. Except where noted all ppm values are given corrected to zero percent O_2, dry basis (i.e., at stoichiometric conditions). To convert ppm values from 0% O_2 to 3% O_2 multiply the ppm value at 0% O_2 by 0.857.

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INTRODUCTION TO PULVERIZED COAL COMBUSTION SEMINAR

Presented at

U. S. Environmental Protection Agency
Research Triangle Park, North Carolina

June 1973

By

E. E. Berkau

U. S. Environmental Protection Agency
Office of Research and Development
Control Systems Laboratory
National Environmental Research Center
Research Triangle Park, North Carolina 27711

COAL COMBUSTION SEMINAR

Good morning, I would like to thank you for taking the time to attend our meeting and hope that you find it of value. The subject, as you know, relates to EPA's research and development activities for control of air pollutant emissions from the combustion of pulverized coal. To review and discuss the work we have invited representatives from industry and other government agencies who are intimately involved with the burning of coal. A list of attendees, as well as copies of the papers to be presented, will be made available to each of you.

The meeting is being sponsored by the Combustion Research Section (CRS) of the Control Systems Laboratory. Our responsibilities are to research and develop economical and efficient combustion modification techniques for the control of air pollutant emissions from burning of conventional and waste fuels in all stationary combustion systems. EPA's Combustion Control Program was officially formulated about 2 years ago although EPA and formerly NAPCA have been involved with combustion studies for many years. To date our efforts have concentrated on control of nitrogen oxides and combustible emissions such as carbon, carbon monoxide, and unburned hydrocarbons from pulverized coal combustion.

Our program consists of coordinated in-house and contracted studies. We have selected this approach to allow us in the Combustion Research Section to become technically involved with the direction and development of combustion control technology. We feel that this approach is essential (1) if we are to understand the practical problems involved in the development and application of technology to conventional combustion systems and processes, and (2) to establish private industry's confidence in our abilities and thereby encourage industry to participate in and accept the results of our R&D efforts to control air pollutant emissions.

While this meeting is concerned only with coal combustion, we would like to use the seminar as a tool for disseminating technical information and for obtaining guidance and participation of industry and other government agencies in our studies. We feel this approach will provide several benefits: (1) industry will receive the technical results of our work before the final reports are distributed; (2) industry can have input to, and thereby affect the direction of, our studies at critical stages; and (3) industry can coordinate or integrate their own activities with ours. It is anticipated that the format for future meetings will be similar to this one; but the subject could relate to either specific combustion hardware or other fuels and will be largely dependent upon the progress in our R&D efforts. However, future meetings will always be designed to emphasize applications of technology for industrial utilization. Your comments as to the suitability of this approach and the adequacy of the present meeting for these purposes will be appreciated.

The specific purpose of the present meeting is for us to review the Combustion Research Section's in-house and contract studies designed to develop combustion modification technology for control of NO_x and combustible emissions from pulverized coal fired boilers. The studies which will be presented for your review and discussion encompass very fundamental research through field testing of practical applications of combustion control technology. The former are designed to provide quantified understanding of the conditions leading to the formation of pollutants and will establish the basis or foundation for the ultimate in combustion control technology. For example, Rocketdyne of Rockwell International will present the results of their work to decipher the combustion chemistry and kinetics of fuel nitrogen conversion to NO_x. On the other extreme, Combustion Engineering and TVA will discuss their plans to establish installation and operating costs and develop design guidelines through applications of combustion control methods to actual field utility boilers. Emphasis will be placed on techniques which have been established from our field testing program to be effective for NO_x control of pulverized coal fired utility boilers and which will be described by ESSO Research & Engineering. In support of the TVA and CE long term development studies the U. S. Bureau of Mines will present their preliminary data on the design and NO_x control limitations of various combustion modification techniques for a four burner, 500#/hr experimental boiler.

A number of other studies lying between the very fundamental and the field testing have also been included in the agenda. The International Flame Research Foundation's (IFRF) Research Station in IJmuiden, Holland, will review their work to develop single burner design criteria to control pollutant emissions from coal and oil fired boilers, and Babcock & Wilcox will discuss their studies to establish the more promising individual or combination NO_x combustion control techniques for use with current burner/boiler design practice. EPA's in-house study to coordinate the IFRF and B&W work with coal and other related fuels (gas, oil) R&D contracts will also be summarized.

Since technology derived from subscale studies with single burner experimental equipment must ultimately be tested and applied to field units of much greater size (100 times larger) and involving banks of burners (16 or more), two other studies are apropos to the meeting. The Jet Propulsion Laboratory (JPL) in Pasadena, California, will investigate for EPA on a laboratory scale the effects of multiburner arrays on single burner NO_x control techniques. Since this study has just been initiated, there are no results to present. However, to introduce you to JPL, we have asked them to present the results of their company sponsored bench scale coal combustion studies. Finally, KVB Engineering, who will be conducting our industrial boiler field testing program, has been asked to present the results of their company sponsored studies to arrive at criteria for scaling up combustion control technology from subscale test data.

I have briefly summarized the objectives of the meeting and introduced the topics to be discussed. I would like to reiterate, however, that the overall purpose of this meeting is to make you aware of, and hopefully a part of, EPA's combustion research and development program. Through your involvement we can be assured that air pollutant emissions will be controlled through the development and application of technically and economically sound technology. The initial step toward this rapport can be accomplished through your active participation in the meeting. Therefore, we invite your comments, discussion and recommendations for the technical activities as well as for future meetings. To provide you with guaranteed attentive ears for your comments, I would like to introduce the members of the Combustion Research Section and mention briefly their primary responsibilities in the Combustion Control Program. They are:

R. E. Hall - Industrial equipment surveys and field testing of conventional stationary combustion systems.

J. H. Wasser - In-house testing of conventional commercial combustion systems.

D. G. Lachapelle - Applications of combustion control technology to conventional stationary combustion systems.

D. W. Pershing - Research & Development of combustion techniques for control of air pollutant emissions from combustion fuels.

G. B. Martin - Characterization of the emission types and levels from the combustion of fuels and the identification of potential combustion control techniques.

To proceed with the program, I will now turn the meeting over to Bob Hall. Bob has been responsible for the planning and organization of the Seminar and for making all arrangements. He has a few announcements to make before introducing the first speaker. Thank you.

FUNDAMENTAL RESEARCH

PART I

INVESTIGATION OF THE MECHANISM AND CHEMISTRY OF FUEL NITROGEN CONVERSION TO NITROGEN OXIDES IN COMBUSTION

BY

A. E. AXWORTHY AND M. SCHUMAN

ROCKETDYNE DIVISION/ROCKWELL INTERNATIONAL
CANOGA PARK, CALIFORNIA

PRESENTED AT THE

COAL COMBUSTION SYMPOSIUM
ENVIRONMENTAL PROTECTION AGENCY
TRIANGLE PARK, NORTH CAROLINA
19-20 JUNE 1973

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INVESTIGATION OF THE MECHANISM AND CHEMISTRY OF FUEL NITROGEN CONVERSION TO NITROGEN OXIDES IN COMBUSTION

by

A. E. Axworthy and M. Schuman

Rocketdyne Division/Rockwell International
Canoga Park, California

INTRODUCTION

This presentation is a progress report covering approximately the first half of an analytical and experimental program being conducted to determine and model the kinetics and mechanism of the decomposition of fuel nitrogen compounds,* the fate of the nitrogen-containing pyrolysis products, and the important physical and chemical processes in the formation of nitrogen oxides from these species in flames. Much of the background information pertinent to this study is presented in an excellent review by Sternling and Wendt (Ref. 1). The general objective of the program is listed in Table 1 and a program outline is presented in Table 2.

Figure 1 shows the probable chemical path for the formation of "thermal NO" and hypothetical example of potential chemical paths for the formation of "fuel NO". Thermal NO is that which forms from the conversion of molecular nitrogen in air to NO during combustion and fuel NO is that which forms from nitrogen compounds present in fossil fuels. The chemical mechanisms are undoubtedly not independent because intermediates formed from fuel nitrogen have the potential to react with NO or with N atoms formed in the Zeldovitch mechanism to form N_2. The paths for the formation of thermal NO from N_2

---

*The chemically bound nitrogen compounds present in fuel oils and coals.

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TABLE 1. PROGRAM OBJECTIVE

THE OBJECTIVE OF THIS PROGRAM IS TO DEVELOP A REALISTIC MATHEMATICAL COMBUSTION MODEL FOR THE FORMATION OF NITROGEN OXIDES FROM THE CHEMICALLY BOUND NITROGEN COMPOUNDS PRESENT IN FOSSIL FUELS AND TO INVESTIGATE EXPERIMENTALLY THE IMPORTANT PHYSICAL AND CHEMICAL PROCESSES INVOLVED IN THE FORMATION OF "FUEL NO".

TABLE 2. PROGRAM OUTLINE

PHASE IA - THEORETICAL ANALYSIS

- PYROLYSIS OF FUEL NITROGEN COMPOUNDS (PREFLAME REACTIONS)
- FORMATION OF THERMAL AND FUEL NO
- MODELING OF OIL DROPLET/COAL PARTICLE BURNING

PHASE IB - FUEL DECOMPOSITION EXPERIMENTS

- PYROLYSIS OF MODEL FUEL NITROGEN COMPOUNDS (DECOMPOSITION KINETICS AND PRODUCT DISTRIBUTION)
- PYROLYSIS OF FUEL OILS AND COALS (DETERMINE INITIAL PRODUCTS OF FUEL NITROGEN COMPOUNDS)

PHASE IIA - NITROGEN COMPOUND COMBUSTION EXPERIMENTS

- BURNER STUDIES WITH INTERMEDIATES FORMED IN PREFLAME REACTIONS OF FUEL NITROGEN COMPOUNDS
- EFFECTS OF INTERMEDIATE CHEMICAL TYPE AND COMBUSTION CONDITION ON CONVERSION TO NO_x

PHASE IIB - MATHEMATICAL CORRELATIONS

- MODEL FOR FUEL NO FORMATION
- EXTEND DROPLET/PARTICLE MODELS TO COMBUSTION OF PARTICLE ENSEMBLES UNDER REALISTIC CONDITIONS

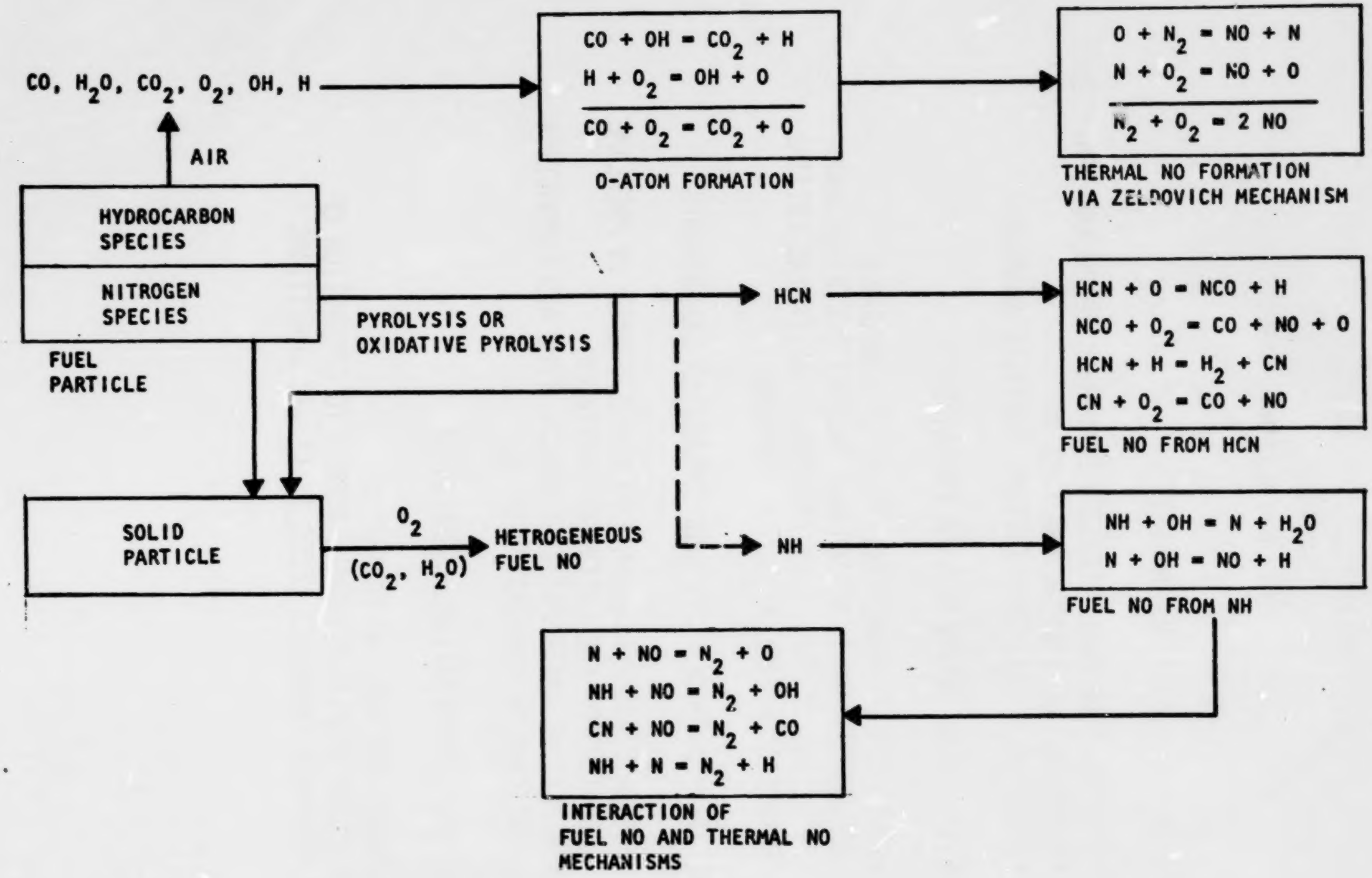

CO, H2O, CO2, O2, OH, H
AIR
HYDROCARBON SPECIES
NITROGEN SPECIES
FUEL PARTICLE
CO + OH = CO2 + H
H + O2 = OH + O
CO + O2 = CO2 + O
O-ATOM FORMATION
O + N2 = NO + N
N + O2 = NO + O
N2 + O2 = 2 NO
THERMAL NO FORMATION VIA ZELDOVICH MECHANISM
PYROLYSIS OR OXIDATIVE PYROLYSIS
HCN
HCN + O = NCO + H
NCO + O2 = CO + NO + O
HCN + H = H2 + CN
CN + O2 = CO + NO
FUEL NO FROM HCN
SOLID PARTICLE
O2
(CO2, H2O)
HETROGENEOUS FUEL NO
NH
NH + OH = N + H2O
N + OH = NO + H
FUEL NO FROM NH
N + NO = N2 + O
NH + NO = N2 + OH
CN + NO = N2 + CO
NH + N = N2 + H
INTERACTION OF FUEL NO AND THERMAL NO MECHANISMS

Figure 1. Potential Paths for NO Formation

under fuel-rich conditions by reactions not involving O atoms, as proposed by Fenimore and Iverach, are not included in Fig. 1.

The mechanisms shown for the formation of fuel NO in Fig. 1, which are highly speculative, indicate the possible complexity of the formation of NO from fossil fuels. The HCN path is included because experiments conducted during this program have shown that under certain conditions the nitrogen contained in coal, fuel oils, and model compounds can be converted nearly quantitatively to HCN. The HCN reactions listed are those presented in Ref. 1. The NH mechanism in Fig. 1 is of the type proposed by Fenimore (Ref. 2) to account for the similar behavior of various nitrogen compounds including ammonia. However, if soot particles are present, the thermodynamically favored reaction $NH_3 + C_s = HCN + H_2$ makes an HCN mechanism plausible even with NH_3. A reaction between HCN and OH should be added as a likely initial reaction in the formation of fuel NO.

The heterogeneous formation of fuel NO is a very likely path not only in the case of coal particles but with fuel oils, also. Experimental results obtained during this program indicate that even volatile heterocyclic nitrogen compounds have a strong tendency to form carbonaceous residues during pyrolysis and these residues contain considerable nitrogen. Thus, nitrogen-containing soot particles could form in oil droplet combustion leading to heterogeneous fuel NO formation in the flame front.

COMBUSTION MODELS

As shown in Fig. 2, the droplet particle combustion models being developed are of three types: (1) droplet vaporization model, (2) droplet/particle flame-front model, and (3) heterogeneous coal combustion model. These have been combined with the necessary chemical reaction rate constants to give an average film kinetic/diffusion model that includes the rate of formation of thermal NO. Chemical reactions are being added for the formation of fuel NO but the calculated fuel NO formation rates will be only qualitative at present because of the uncertainties in the reaction mechanisms and rate constants.

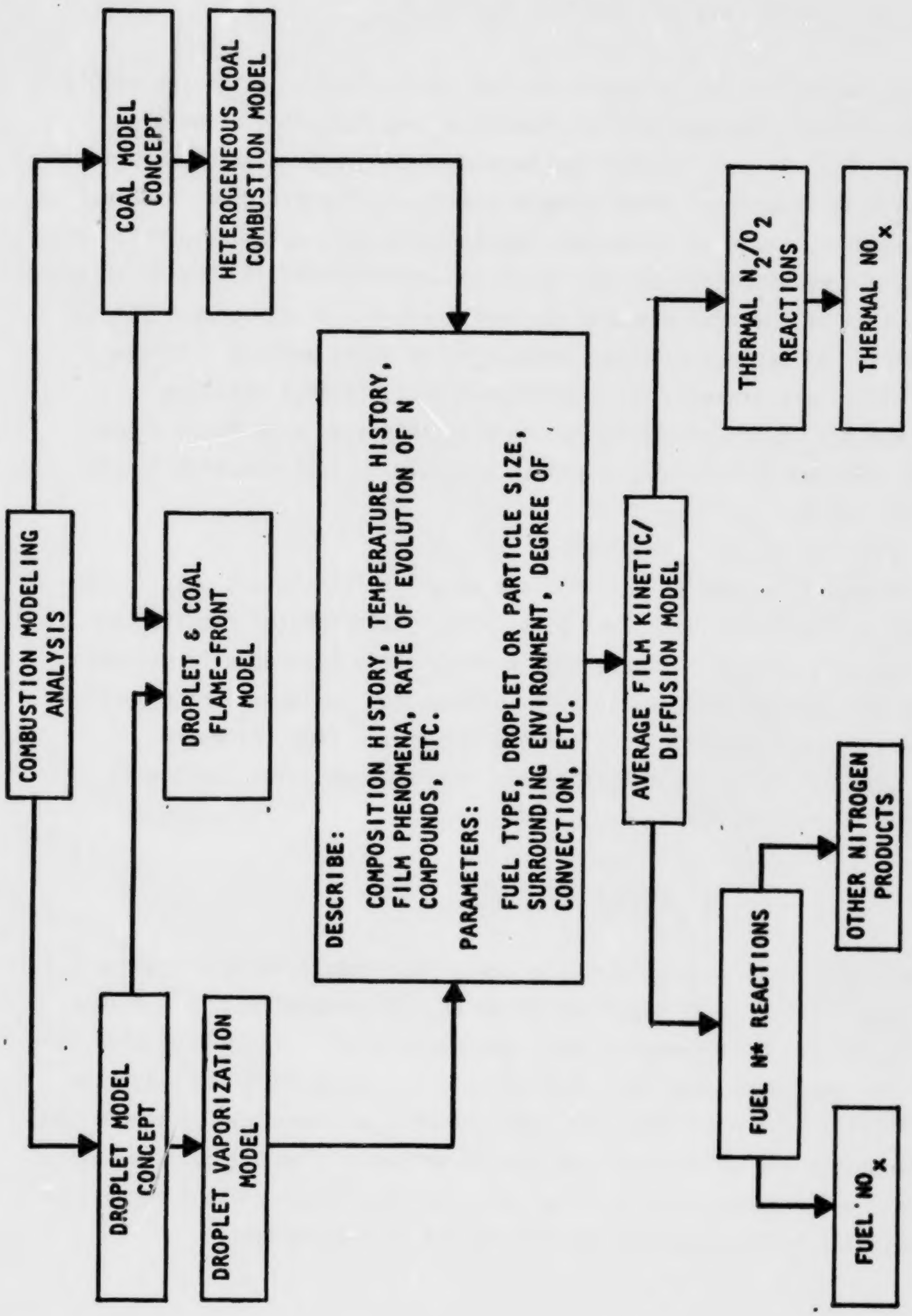

COMBUSTION MODELING ANALYSIS
DROPLET MODEL CONCEPT
COAL MODEL CONCEPT
DROPLET VAPORIZATION MODEL
DROPLET & COAL FLAME-FRONT MODEL
HETEROGENEOUS COAL COMBUSTION MODEL
DESCRIBE:
COMPOSITION HISTORY, TEMPERATURE HISTORY, FILM PHENOMENA, RATE OF EVOLUTION OF N COMPOUNDS, ETC.
PARAMETERS:
FUEL TYPE, DROPLET OR PARTICLE SIZE, SURROUNDING ENVIRONMENT, DEGREE OF CONVECTION, ETC.
AVERAGE FILM KINETIC/ DIFFUSION MODEL
FUEL N* REACTIONS
THERMAL N_2/O_2 REACTIONS
FUEL NO$_x$
OTHER NITROGEN PRODUCTS
THERMAL NO$_x$

Figure 2. Combustion Modeling Analysis

It can be seen from Fig. 3 through 5 that the heterogeneous coal combustion model developed on this program gives results that agree with the coal particle composition histories measured by Howard and Essenhigh (Ref. 3). Inspection of the initial time region of the volatile matter and fixed carbon contents shown in Fig. 3 and 4 suggests that during the first 0.05 seconds, volatile matter is evolved without heterogeneous combustion. The heterogeneous combustion then begins at a sufficiently high rate that volatile matter loss due to heterogeneous combustion is as fast or faster than the volatile matter loss due to gaseous evolution. After about 0.2 seconds, the volatile reactions become very slow and the remainder of the volatile material is lost due to heterogeneous combustion (Fig. 5). The reactions of CO_2 and H_2O at the solid surface (Table 3) have been added to the coal combustion model. The importance of these reactions on the result obtained is being investigated.

The chemical reactions presently included in the kinetic/diffusion model are listed in Table 4. The results of a preliminary calculation with the kinetic/diffusion model for a No. 2 fuel oil are shown in Fig. 6. Under the conditions of this calculation (relatively low flame temperature), the diffusion of species to the droplet surface is quite rapid. The temperature at the flame zone (and, therefore, the rate of formation of thermal NO) is strongly dependent on the free-stream temperature with this model. Therefore, the use of this model to predict the rate of formation of thermal NO must await extention of the model during Phase II.

The concentrations of CO and O in Fig. 6 are very much greater than the predicted equilibrium values. This appears to result mainly from allowing all of the fuel to react to CO rather than CO_2. High oxygen atom concentrations then form by the reactions shown at the top of Fig. 1. This overshoot will be controlled by reducing the fraction of reaction that goes to CO.

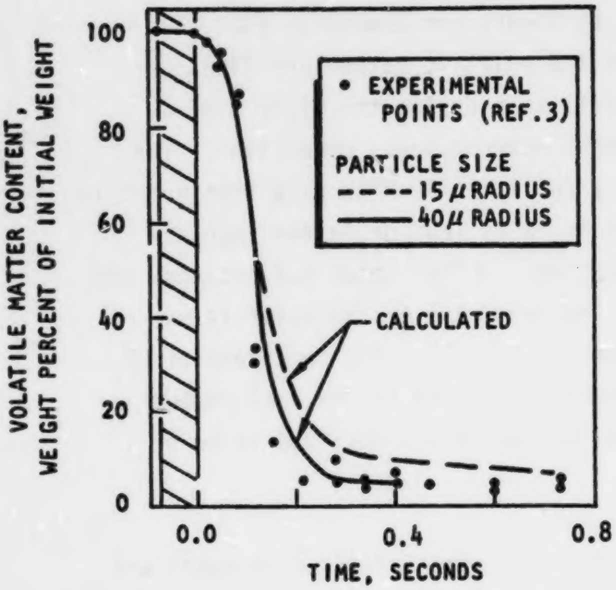


Figure 3. Volatile Matter Content

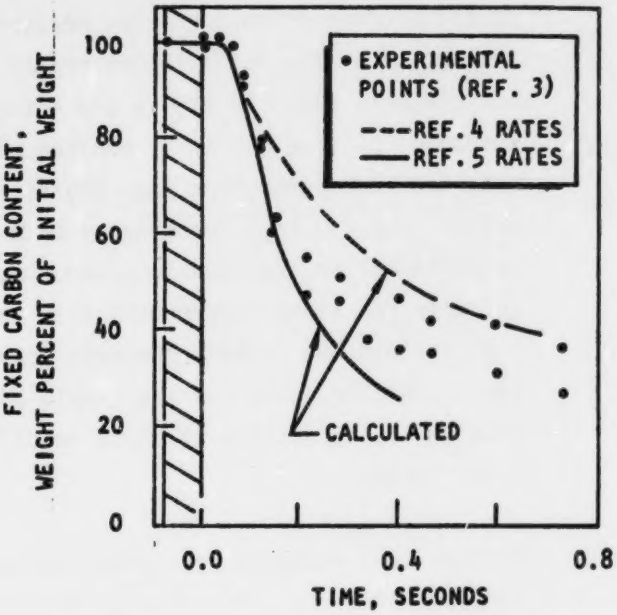


Figure 4. Fixed Carbon Content

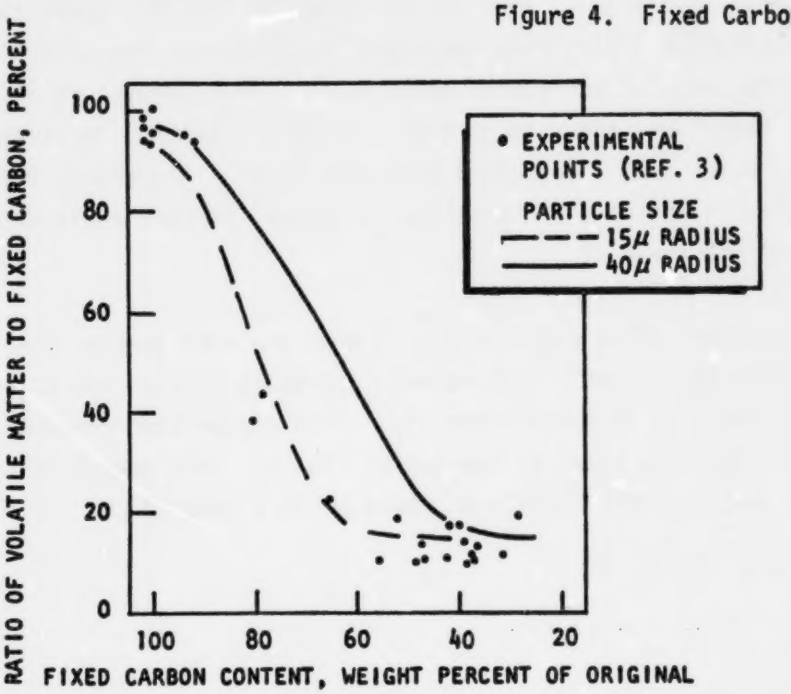


Figure 5. Variation of Composition of Solid Material With Degree of Burnout

TABLE 3. COAL COMBUSTION MECHANISM

CHEMISORPTION REACTIONS:

$$C_F + O_2 \xrightarrow{\kappa_1} C_o + O$$

$$C_F + O \xrightarrow{\kappa_2} C_o$$

$$C_F + CO_2 \underset{\kappa_4}{\overset{\kappa_3}{\rightleftharpoons}} CO + C_o$$

$$C_F + H_2O \underset{\kappa_6}{\overset{\kappa_5}{\rightleftharpoons}} H_2 + C_o$$

GASIFICATION REACTION:

$$C_o \xrightarrow{\kappa_7} CO + C_F$$

WATER-GAS SHIFT REACTION:

$$CO + H_2O \underset{\kappa_9}{\overset{\kappa_8}{\rightleftharpoons}} CO_2 + H_2$$

COAL REACTION RATE:

$$\dot{N}_C \left[\left(\frac{\kappa_1}{\kappa_7}\right) (O_2) + \left(\frac{\kappa_2}{\kappa_7}\right) (O) + \left(\frac{\kappa_3}{\kappa_7}\right) (CO_2) + \left(\frac{\kappa_4}{\kappa_7}\right) (CO) + \left(\frac{\kappa_5}{\kappa_7}\right) (H_2O) + \left(\frac{\kappa_6}{\kappa_7}\right) (H_2) + 1 \right]$$

$$= (C_T) \left[\kappa_1 (O_2) + \kappa_2 (O) + \kappa_3 (CO_2) + \kappa_5 (H_2O) \right]$$

TABLE 4. REACTIONS FOR THE KINETIC/DIFFUSION MODEL (EXCLUDING FUEL NITROGEN REACTIONS)

1. $C_N H_M + \frac{N}{2} O_2 = N\ CO + \frac{M}{2} H_2O$

2. $CO + OH = CO_2 + H$

3. $O_2 + H_2 = 2\ OH$

4. $OH + H_2 = H_2O + H$

5. $O_2 + H = OH + O$

6. $O + H_2 = OH + H$

7. $O + H_2O = 2\ OH$

8. $2H + M = H_2 + M$

9. $2\ O + M = O_2 + M$

10. $O + H + M = OH + M$

11. $H + OH + M = H_2O + M$

12. $N_2 + O = NO + N$

13. $N + O_2 = NO + O$

14. $N + O + M = NO + M$

15. $N + OH = NO + H$

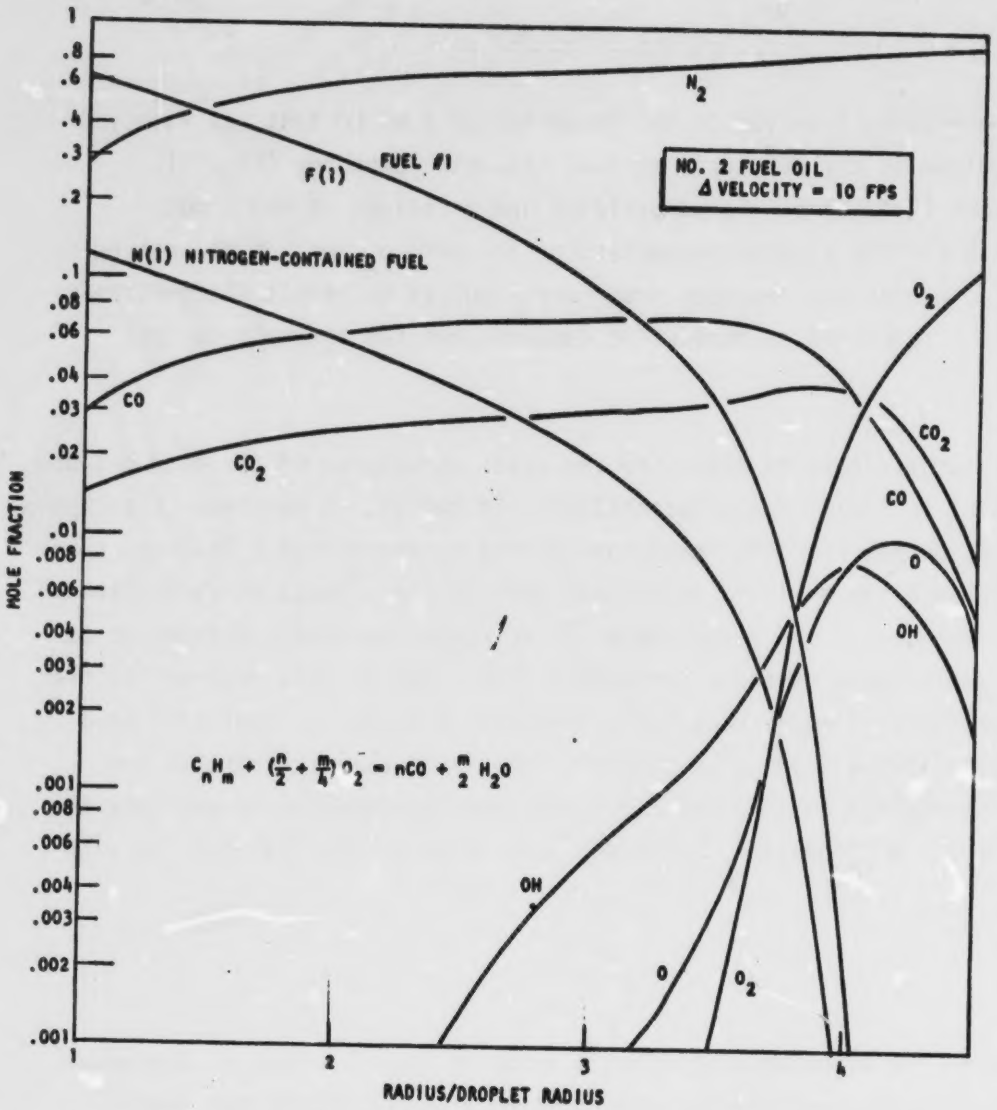


Figure 6. Preliminary Results With Flame-Front Model

PYROLYSIS EXPERIMENTS

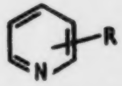
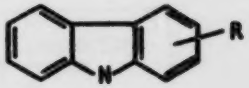
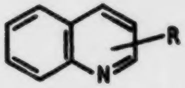
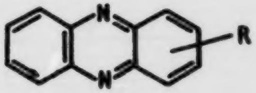
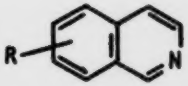
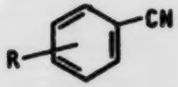
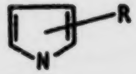
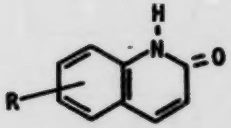
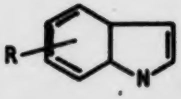
One of the processes involved in the formation of fuel NO that has received little attention is the pyrolysis of fuel nitrogen compounds (Fig. 1). Hurd and Simon (Ref. 6) pyrolyzed pyridine and picolines at 850 C but did not establish the kinetic parameters or the fate of most of the nitrogen. An activation energy and reaction order are required to permit the pyrolysis rates to be extrapolated to combustion temperatures for the mathematical models.

Although it is difficult to determine the exact structures of the nitrogen compounds present in fossil fuels (particularly in coals), it has been established that they are mainly aromatic compounds--mostly heterocyclics. The structures listed in Table 5 are believed to include most of the classes of fuel nitrogen compounds. Because of the large number of nitrogen compounds believed to be present in fuels, most of the experimental effort during this program has been with the pyrolysis of model nitrogen compounds. A number of fuel oils have also been pyrolyzed and one coal sample. Additional coal experiments are planned using a rapid heating technique that was developed to investigate the pyrolysis of solid propellant ingredients and is being modified for use with coal.

APPARATUS

A schematic of the experimental setup is shown in Fig. 7. Most of the model compound experiments involved the vaporization of a 0.2 microliter sample into a helium stream that flows through a quartz reactor. The reactor is 2.2 mm ID with a volume of 1.2 cc and a nominal residence time of 0.75 seconds. Experiments were also conducted with a vapor injector in which the sample vapor was premixed with He or He/O_2 and a 1 cc slug introduced into the He stream before it entered the reactor. The organic products were identified by temperature-programmed gas chromatography and mass spectrometry. HCN and NH_3 were trapped in neutralizing solutions and determined, respectively, by a

TABLE 5. NITROGEN COMPOUNDS IN FOSSIL FUELS

PYRIDINES		CARBAZOLES	
QUINOLINES		PHENAZINES	
ISO-QUINOLINES		BENZONITRILES	
PYRROLES		QUINOLONES	
INDOLES			

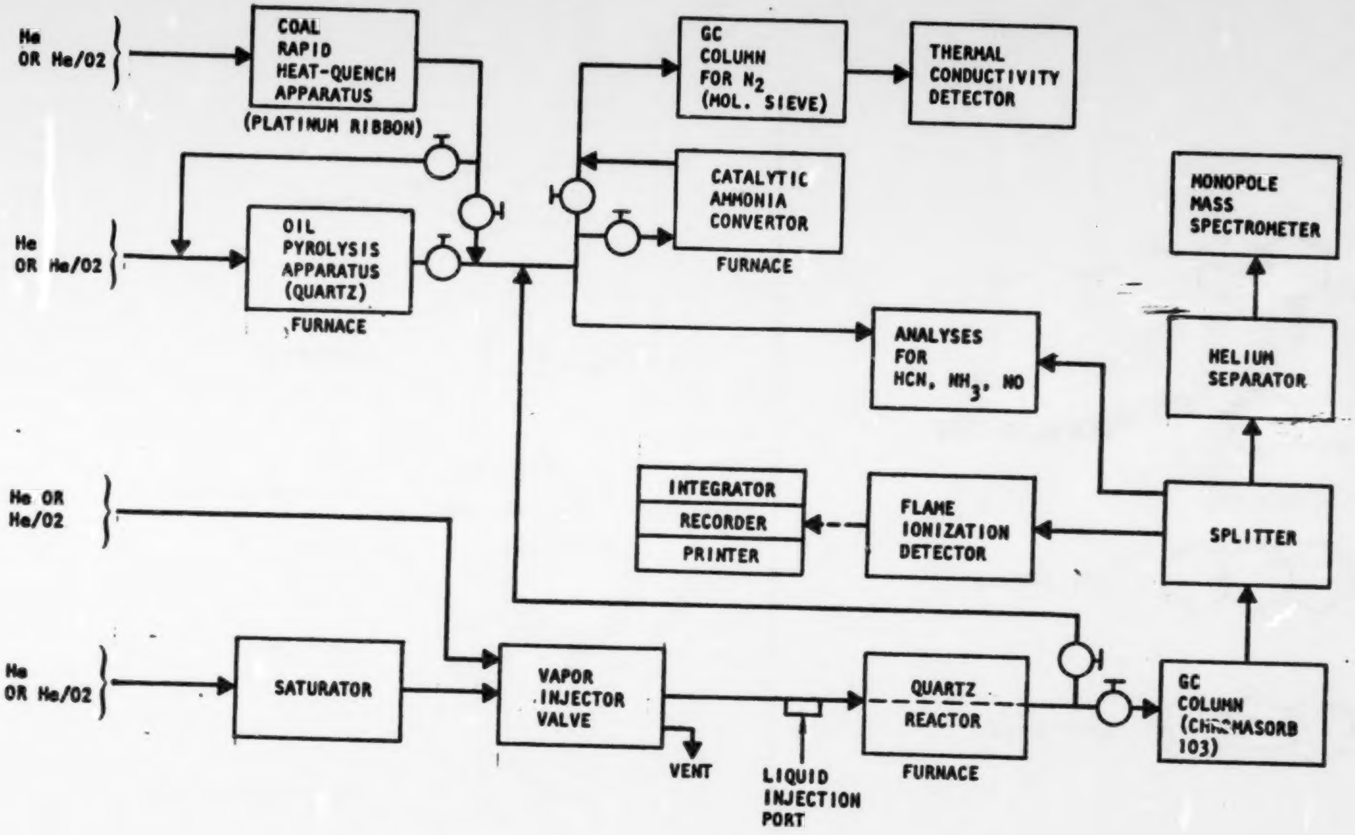

He OR He/02
COAL RAPID HEAT-QUENCH APPARATUS
(PLATINUM RIBBON)
He OR He/02
OIL PYROLYSIS APPARATUS (QUARTZ)
FURNACE
GC COLUMN FOR N_2 (MOL. SIEVE)
THERMAL CONDUCTIVITY DETECTOR
CATALYTIC AMMONIA CONVERTOR
FURNACE
MONOPOLE MASS SPECTROMETER
ANALYSES FOR HCN, NH_3, NO
HELIUM SEPARATOR
He OR He/02
INTEGRATOR
RECORDER
PRINTER
FLAME IONIZATION DETECTOR
SPLITTER
He OR He/02
SATURATOR
VAPOR INJECTOR VALVE
VENT
LIQUID INJECTION PORT
QUARTZ REACTOR
FURNACE
GC COLUMN (CHROMASORB 103)

Figure 7. Schematic of Apparatus

cyanide specific electrode and Nessler's reagent. N_2 was measured on a molecular sieve column GC. Between experiments, the chromasorb 103 column was back flushed and the residue in the reactor burned out. The oil pyrolysis experiments were conducted in a similar manner except that the reactor had a 2 cc bubble blown near the center and the sample was introduced into the heated reactor by quickly moving a small quartz boat containing 1 to 2 milligrams of oil into the heated zone. The initial coal experiments were conducted in this oil pyrolysis apparatus.

MODEL COMPOUND EXPERIMENTS

The model compounds chosen for study were pyridine, pyrrole, quinoline, and benzonitrile. These represent many of the nitrogen structures shown in Table 5. The nitrogen compounds present in the fossil fuels are highly substituted and of much higher molecular weights but it is expected that experiments with these parent compounds will be indicative of the types of high-temperature reactions that can occur with chemically bound nitrogen.

Decomposition Rates as a Function of Temperature

Pyrolysis experiments were conducted at temperature intervals of about 25 degrees. The experimental decomposition curves obtained for the model compounds (in helium) are shown in Fig. 8. Pyridine and pyrrole gave similarly shaped curves with slopes that remained steep until beyond 95 percent decomposition. The pyrrole is less stable than pyridine, the curves being separated by about 60 degrees. Quinoline gave a decomposition curve that is nearly linear with temperature. Quinoline is less stable than all of the other compounds below 910 C but is more stable than pyrrole above that temperature. Quinoline is unusual in that its decomposition curve remains steep up to about 960 C and then tails out to high temperatures. In fact, 4 percent remained undecomposed even at a temperature of 1100 C. Thus below 1000 C, pyridine is more stable than benzonitrile, while above 1000 C, the reverse is true.

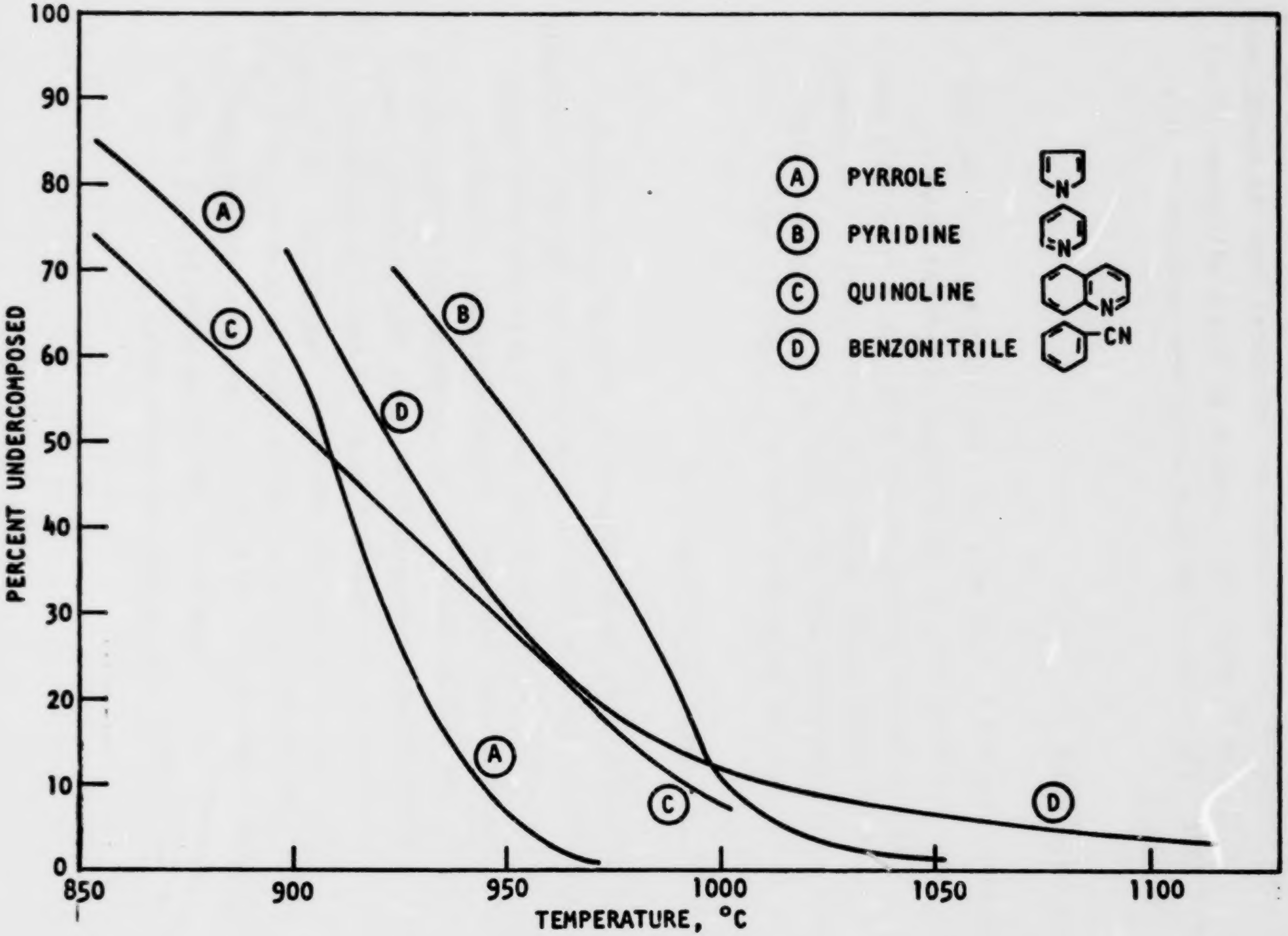


Figure 8. Model Compound Decomposition Curves in Quartz (at a nominal residence time of 0.75 seconds, helium carrier gas)

The experimental decomposition curves were fitted to rate expressions for use in the combustion models. Figure 9 shows the pyridine pyrolysis curve* plotted in a semi-log form along with three theoretical first-order rate expressions. It is apparent that the data fit a first-order expression with an activation energy of 70 kcal/mole. Similar first-order fits were obtained for the pyrrole and quinoline data giving the rate parameters listed in Table 6. The benzonitrile data are still being analyzed and it appears that a complex rate expression may be involved.

The rate parameters obtained for pyridine and pyrrole indicate that the rate-determining step is a unimolecular reaction. Such reactions typically have pre-exponential factors in the range of 10^{13} to 10^{16} $\sec^{-1}$ (Ref. 7). The surprising feature is that pyrrole, which is less aromatic than pyridine, has a higher activation energy for decomposition. The low quinoline pre-exponential factor suggests a heterogeneous reaction.

Shown in Fig. 10 is an Arrhenius plot of the decomposition half-life of pyridine as a function of temperature. The results of this study and the rates measured by Hurd and Simon fall on the solid line. Figure 10 shows that the (extrapolated) half-life for pyridine is about 0.1 milliseconds at 1800 K and that this extrapolated half-life will be in error about 15 percent for each 1 kcal/mole error in the activation energy.

Pyridine experiments using the vapor injector gave decomposition rates that were slower by about a factor of three than when liquid sample injection was employed. The pyridine concentration in the reactor is estimated to be lower by about a factor of 100 with the vapor injector. This indicates that the reaction is of an order somewhat smaller than one but some other experimental parameters may be changing slightly instead.

Pyridine experiments were conducted with the vapor injector using a mixture of 5 mole percent oxygen in helium as the diluent gas. The data are not yet

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*This curve was from an early experiment that gave a smaller pre-exponential factor than did the curve in Fig. 8.

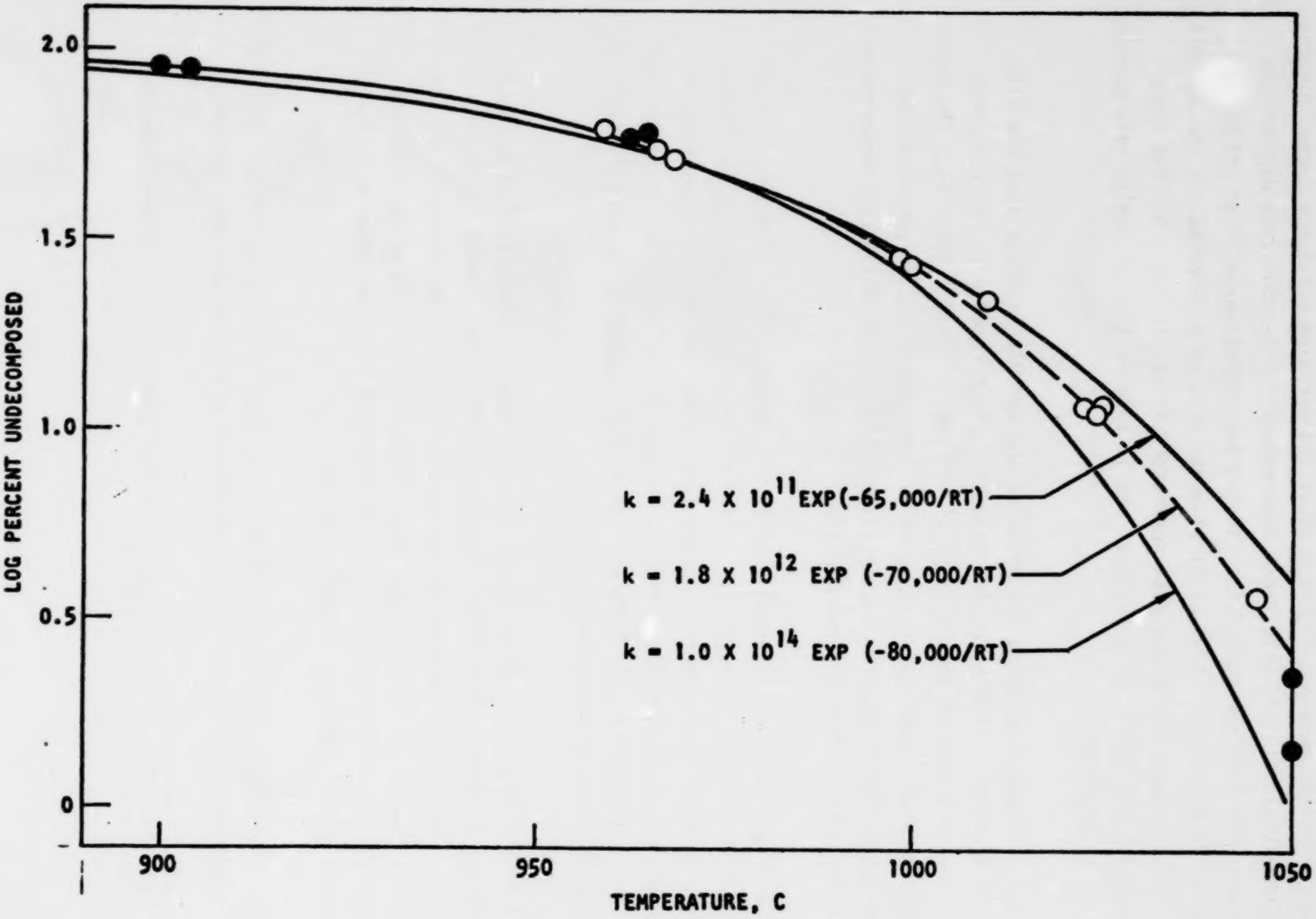

Figure 9. Pyridine Pyrolysis Curve (Log Scale)

TABLE 6. KINETIC PARAMETERS FOR PYROLYSIS OF MODEL COMPOUNDS IN HELIUM

$$-dC/dt = k(C)^N = A \cdot (C)^N \cdot \exp(-E/RT)$$

	N	A*	E, KCAL/MOLE
PYRIDINE	1	2.5×10^{12}	70
PYRROLE	1	5.1×10^{15}	85
QUINOLINE	1	1.8×10^{8}	45
BENZONITRILE**			

*CONCENTRATION UNITS ARE MOLE/CC; TIME UNITS ARE SECONDS

**DATA ANALYSIS NOT COMPLETED

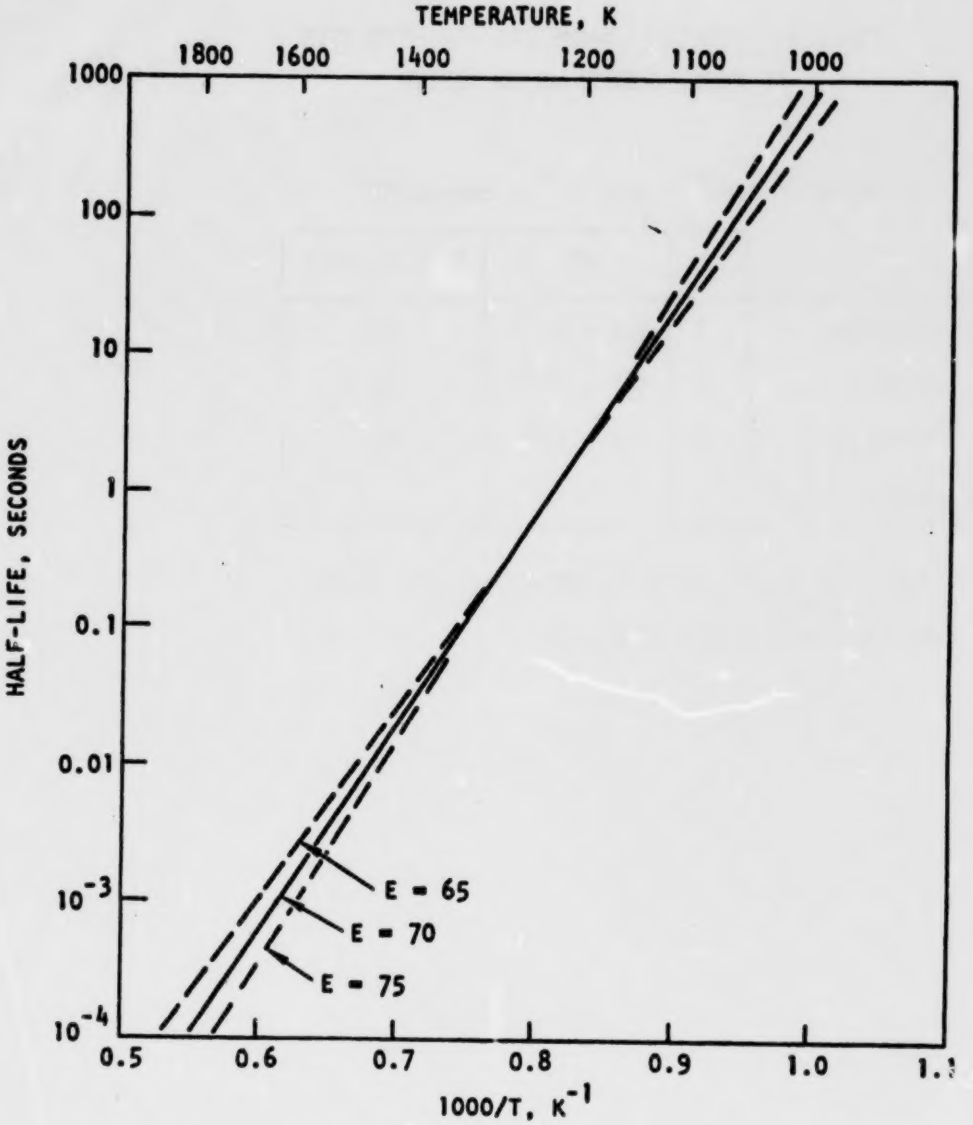

Figure 10. Half-Life for Pyridine Decomposition as a Function of Temperature (Arrhenius Plot)

reduced but the oxidative pyrolysis temperatures are lower by about 100 to 200 degrees for a given extent of decomposition. The oxidative pyrolysis rate parameters will also be included in the combustion models.

Decomposition Products

Only minor amounts of ammonia were detected in the products from the pyrolysis experiments. Additional tests for ammonia are being made using the ammonia convertor (Fig. 7) to decompose the NH_3 to N_2 giving a more sensitive test. The mass balances obtained in the model compound experiments (with helium carrier gas) are summarized in Table 7 as a function of temperature. Depending upon the temperature, from 4 to 100 percent of the carbon is present in the observed products and 0 to 90 percent of the nitrogen is found.

Benzonitrile forms almost no methane, quinoline up to 4 percent methane, pyridine about 10 percent, and pyrrole about 25 percent methane. The other observed organic products, HCN, and a few (as yet unidentified) GC peaks account for from 4 to 74 percent of the carbon under the various conditions. Thus, the unrecovered carbon (believed to be in the carbonaceous residue that forms on the reactor wall) amounts to from 0 to 96 percent of the samples (Table 7).

The amount of HCN formed was strongly temperature dependent ranging from 24 to 89 percent of the nitrogen in the sample at about 1100 C to less than a few percent (near the detection limit) at temperatures of 1000 C and lower. The amount of nitrogen found in the identified organic products ranged from none from benzonitrile to 36 percent for pyrrole. The amount of nitrogen present in the unknown peaks must be small except for pyrrole at 900 C where it could amount to as much as 50 percent of the total nitrogen.

It appears that the unrecovered nitrogen in these experiments is contained in the carbonaceous residue present in the reactor after each experiment. The residue from two experiments with pyridine at 970 C was analyzed for nitrogen by the Dumas method and about two-thirds of the missing nitrogen was

TABLE 7. PRODUCT MASS BALANCES

REACTANT	TEMPERATURE, C	CARBON, PERCENT FOUND IN:					NITROGEN, PERCENT FOUND IN:		
		CH_4	OTHER ORGANIC PRODUCTS	HCN	UNKNOWN PEAKS	RESIDUE BY DIFFERENCE	ORGANIC PRODUCTS	HCN	TOTAL
PYRIDINE	950	12	18	0	10	60	12	<2	12
	1000	10	13	0	2	75	6	2	8
	1050	10	8	10	0	72	2	48	50
	1100	9	4	18	0	69	1	89	90
QUINOLINE	900	1	2	0	1	96	2	N.M.	2
	950	2	6	0	3	89	3	3	6
	1000	4	12	0	2	82	4	<2	4
	1100	4	7	3	0	86	1	24	25
BENZONITRILE	900	0.2	20	0	1	79	0	<4	0
	1000	0.7	19	0	0	80	0	<2	0
	1050	1.2	22	4	0	73	0	34	34
	1100	1.4	12	4	0	83	0	38	38
PYRROLE	900	26	34	0	40	0	36	2	38
	950	27	26	0	3	44	24	N.M.	24
	975	26	18	0	0	56	11	N.M.	11

recovered. Another experiment was conducted in which the residue from the pyrolysis of pyridine at 970 C was heated to 1100 C for 15 minutes. No HCN was evolved indicating that the HCN formed in the high-temperature pyrolysis experiments forms directly in the initial pyrolysis reaction.

The individual organic products that were present in the model compound decomposition products are shown in Fig. 11 through 14. The products obtained from pyridine at the lower temperatures (Fig. 11) are the same as those reprorted by Hurd and Simon but are recovered at much higher concentrations. This probably results from the shorter residence time and the improved experimental procedure.* At higher temperatures, the less thermally stable products decrease in concentration and only the stable products are observed. The products from quinoline (Fig. 12) are similar to those from pyridine (benzene and benzonitrile) except that methane, acetonitrile, and acrylonitrile are at much lower concentrations or absent. It is reasonable that quinoline forms mostly residue since it represents the first step in the condensation of pyridine to residue.

The major products from benzonitrile (Fig. 13) are benzene and biphenyl indicating that the first step is a C-C bond rupture followed by hydrogen abstraction to form benzene and some association of phenyl radicals. The surprising feature is that most of the nitrogen apparently goes into the residue even though the initial formation of CN radicals is indicated.

The experiments with pyrrole, conducted very recently, are interesting in that all of the carbon is recovered at low temperature and possibly most of the nitrogen, i.e., little residue is formed. The unknown that accounts for 48 percent of the carbon at 875 C (Fig. 14) has a retention time on the GC column about the same as do pyridine ard the picolines. It would be quite unexpected

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*It was established during this program that the fraction of pyridine going to residue increases if the residue is allowed to build up (i.e., the residue catalyzes its own formation).

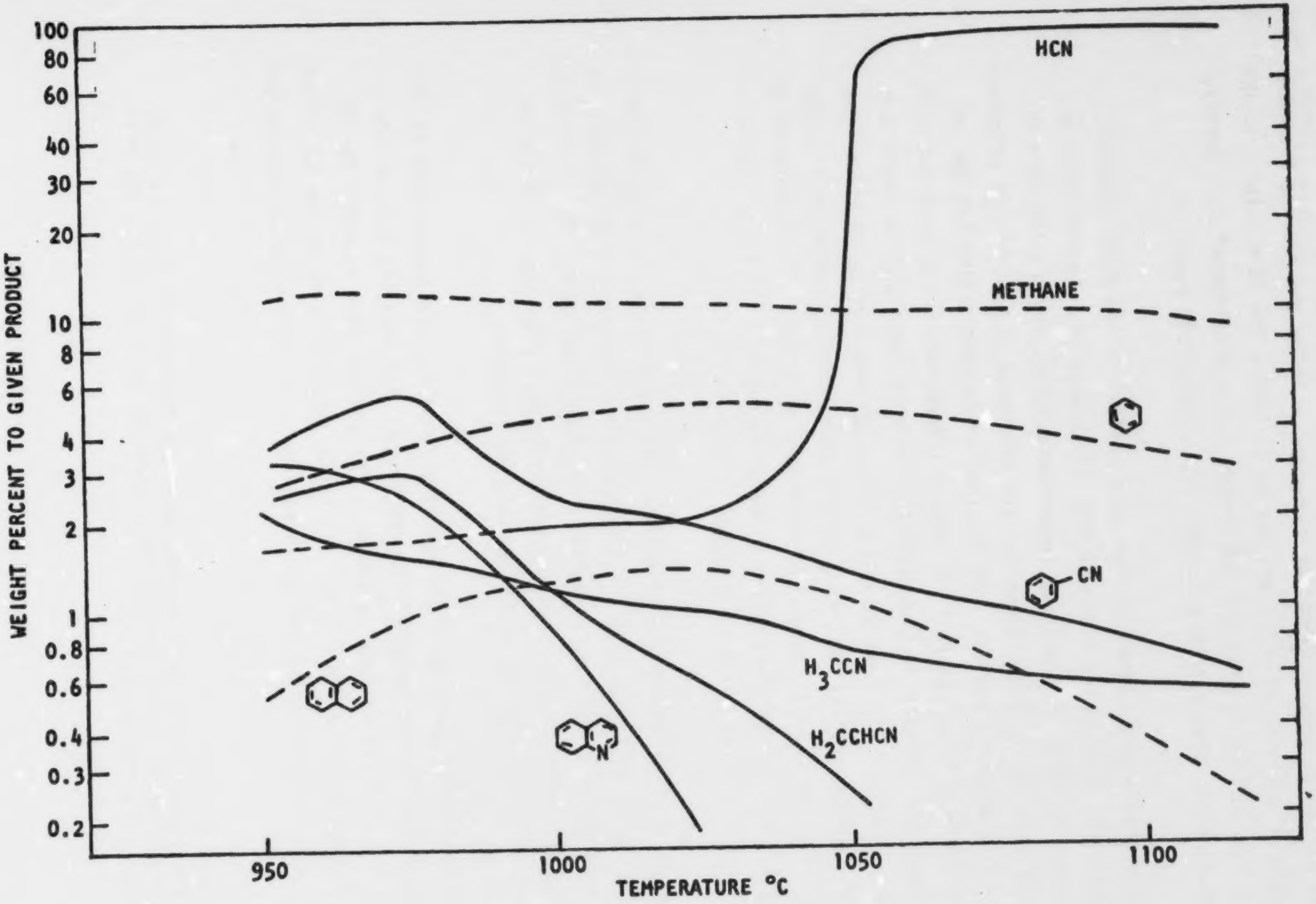

Figure 11. Pyrolysis Products of Pyridine

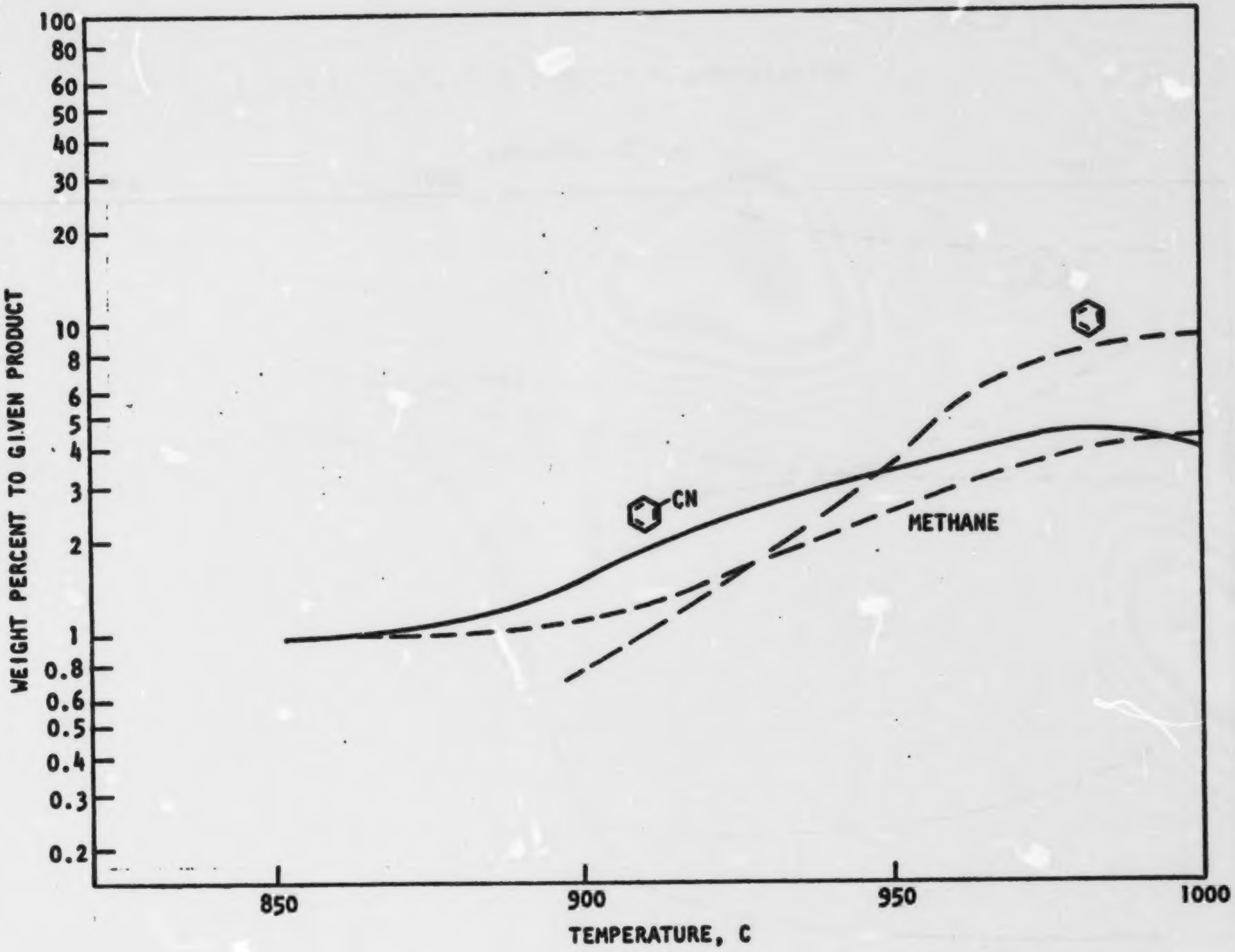

Figure 12. Products of Quinoline Decomposition

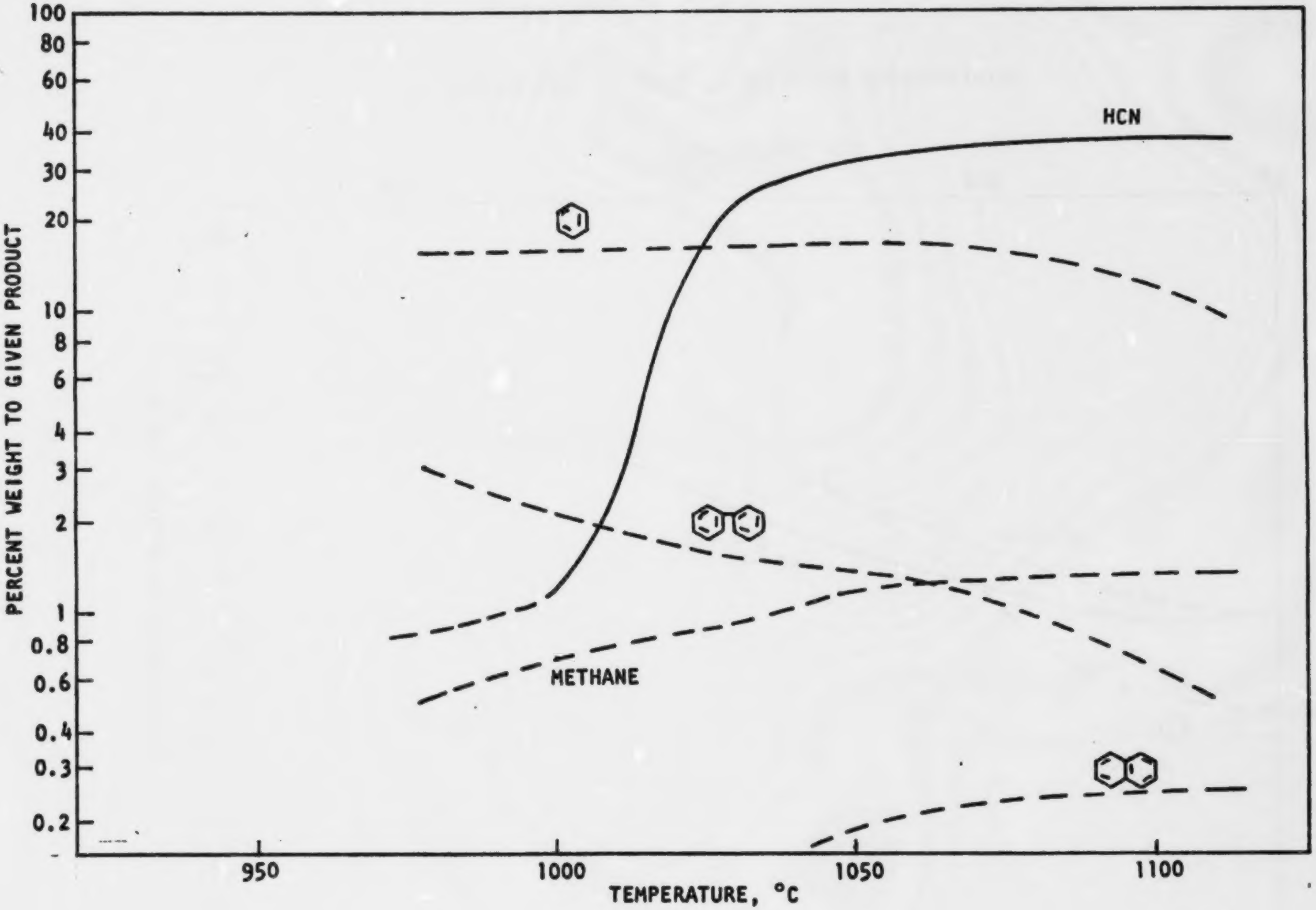

Figure 13. Pyrolysis Products of Benzonitrile

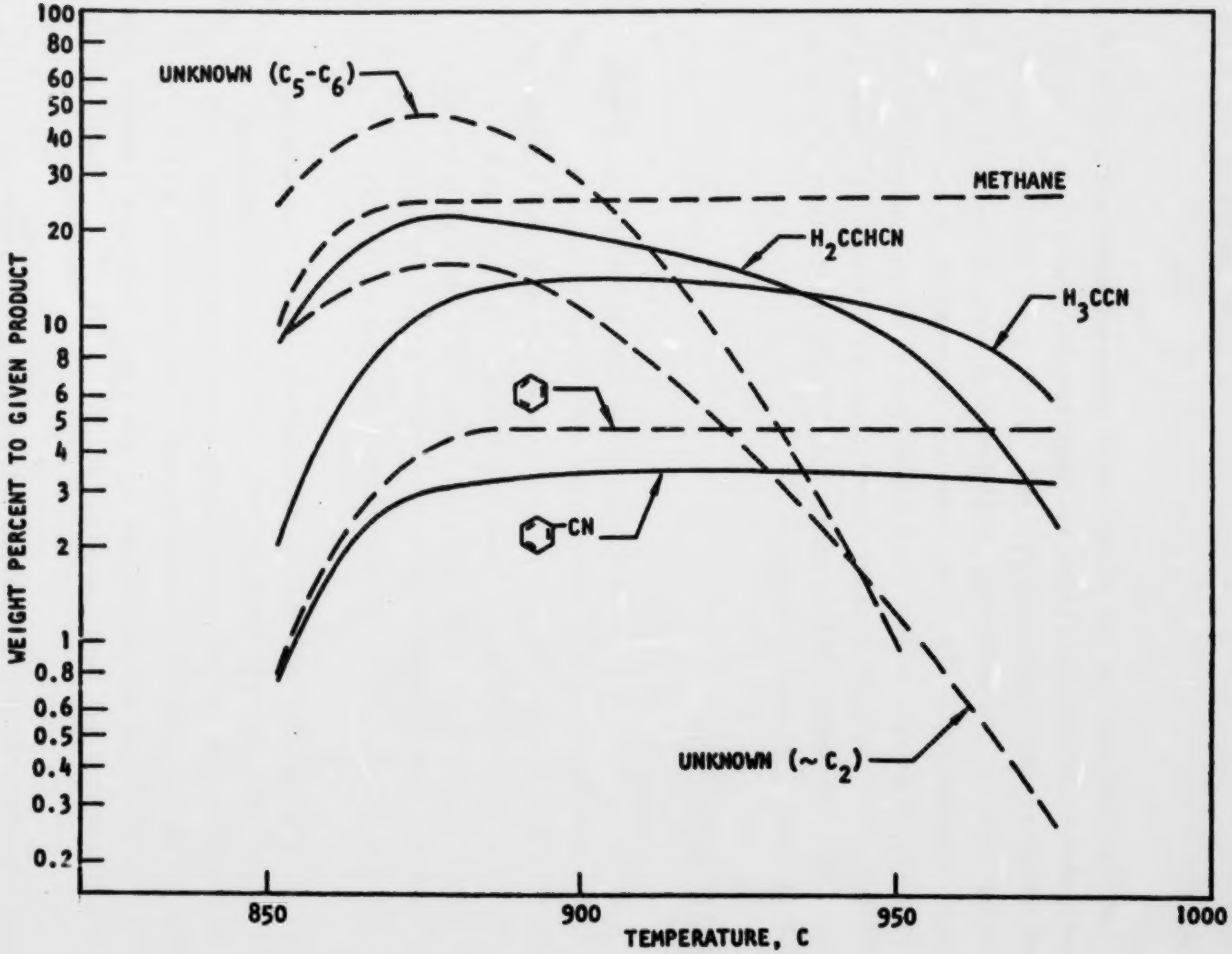

Figure 14. Products of Pyrrole Decomposition

if the first step in pyrolysis of pyrrole turns out to be the formation of the aromatic pyridyl ring.

To summarize the important results of the model compound experiments to date, virtually no ammonia or HCN are formed at lower temperatures but large amounts of HCN are formed at the higher temperatures. It is quite possible that in the combustion process, where heating rates are high, HCN is the only important fuel nitrogen intermediate. The other important observation is that even volatile nitrogen compounds in the vapor phase have a strong tendency to form a solid residue which contains a major fraction of the nitrogen (at lower temperatures). Thus, the heterogeneous combustion of soot particles could be a source of fuel NO in a diffusion flame.

FUEL PYROLYSIS EXPERIMENTS

Six samples of No. 6 fuel oil were pyrolyzed in helium in the oil apparatus at 1100 and 950 C. The amounts of HCN formed are listed in Table 8. Each of these values is the average of two runs that gave moderately good reproducibility. It can be seen that, as with the model compounds, much more HCN is formed at the higher temperature than at the lower. Of the fuel oils, only the first (Table 8) formed appreciable HCN at 950 C. The Wilmington crude also gave considerable HCN at 950 but gave twice as much at 1100 C.

The one coal sample that has been run in this apparatus gave (reproducibly) large quantities of HCN at both temperatures. Calculation of the percent nitrogen that went to HCN is less certain with coals because of the small sample size and the possibility of a nonhomogeneous nitrogen distribution. In addition, this coal sample was determined to have about twice the listed nitrogen content a few months earlier (see below).

It was found that the presence of sulfide ion can cause an interference in the cyanide electrode method used to measure the HCN. Calibration experiments revealed that sulfide ion alone will not be detected as HCN but, in the presence of HCN, sufficient sulfide ion will increase the response factor by about 40

TABLE 8. FUEL PYROLYSIS EXPERIMENTS

	%N	%S	%N AS HCN	
			1100 C	950 C
GULF NO. 6 FUEL OIL (VENEZUALIAN CRUDE)	0.43	2.31	69	47
GULF NO. 6 FUEL OIL (VARIOUS CRUDES)	0.44	0.73	49	5
GULF NO. 6 FUEL OIL (MAINLY CALIFORNIA CRUDE)	1.41	1.63	33	6
CONOCO NO. 6 FUEL OIL	0.3	0.66	<6	---
NO. 6 FUEL OIL (EPA IN-HOUSE)	0.5	0.9	24	4
NO. 6 FUEL OIL (EX-ULTRASYSTEMS)	0.38	0.33	7	---
WILMINGTON CRUDE	0.63	1.59	127	57
COAL (EPA IN-HOUSE)	(0.59)		120	101

TABLE 9. COAL ANALYSES AND VOLATILE NITROGEN RESULTS

COAL	N, %W		% VOLATILES	N, %W IN RESIDUE	%N IN RESIDUE
	JAN '73	MAY '73			
IFRF-A	1.16	0.54, 0.64	27.3	0.16	21.5
IFRF-N	1.47	0.91, 1.16	41.5	0.18	11.5
EPA	1.17	0.60	38.0	0.27	27.8
EPA (DUPLICATE)		0.58	38.9	0.25	26.5

percent. It may be necessary to reduce the HCN values in Table 8 by about one-third. This sulfide interference will have no effect on the model compound results because sulfur was not present. A colorimetric method has been found that will determine HCN accurately in the presence of sulfide ion.

Some of these oils and coals were rerun to investigate the amounts of ammonia and nitrogen that are formed, if any. The data are being reduced but it does appear that these will be important products.

The fuel pyrolysis results were encouraging in that they indicate that real fuels behave similarly to the model compounds. That is, they form large amounts of HCN at the higher temperatures. It is again possible that under combustion conditions these fuels may form HCN quantitatively.

COAL AND RESIDUE ANALYSIS

Three coal samples were analyzed for nitrogen in January 1973 by the Dumas method. The results obtained are shown in the first column of Table 9. These analyses were repeated four months later giving the much lower results shown. The reason for these lower results is not known but sample inhomogeneity must be suspected. After the second series of analyses, the percent volatiles were determined for these coals as well as the percent nitrogen in the residues. It can be seen from Table 9 that only about one-fourth of the nitrogen remained in the residue (or less if the higher nitrogen values are correct). These are smaller amounts of nonvolatile nitrogen than have been estimated previously (Ref. 1).

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ANALYTIC SCALING OF FLOWFIELD AND NITRIC OXIDE IN COMBUSTORS*

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ABSTRACT

The criteria for flow and chemical similarity including nitric oxide formation in turbulent flows are derived from the conservation equations. It is shown that the flowfield and primary combustion product concentrations in fullscale combustors can be practically simulated in laboratory subscale combustors, but that the nitric oxide concentration is proportional to the combustor characteristic dimension if the nonlinear effect of radiation heat loss is neglected. For gas fired combustors, the similarity conditions require only that the geometries and boundary conditions be similar. For oil fired units, only one additional particle size scaling relation must be satisfied. For coal fired units, however, additional burning rate scaling relations are imposed.

1. INTRODUCTION

The similarity conditions for chemically reactive systems has been investigated by Penner (1955), Spalding (1963), and others. Because of the large number of parameters in combustion processes, exact combustion system scaling is impossible. Thus, only partial modeling can be successful; and in typical problems (liquid fuel rocket engines treated by Penner, flame propagation in spark-ignition engines discussed by Spalding, etc.) experience has shown that only a few significant dimensionless groups are important and need be considered in practical modeling and scaling.

The present study considers turbulent diffusion flames in industrial combustors, and special attention is directed at the formation of nitric oxide therein. The scaling approach taken is basically pragmatic although its derivation is mathematical. The objective is to be able to perform simple laboratory experiments in geometrically scaled combustors without pressure or gravity scaling and be able to correctly interpret the measured results in terms of fullscale combustor performance with little error. For this purpose, one must determine those dominant effects which must be scaled correctly and to determine the scaling correction factors for small effects and perturbations.

It is a physically known fact that turbulent transport mechanisms dominate molecular transport mechanisms in industrial combustors and that combustion kinetics are extremely rapid except for kinetically limited contaminant formation. It can be shown that if a combustion medium is optically thick, the turbulent transport process dominates the radiant energy transport process. Gravitational effects are also known to be small in industrial combustors. To good first approximation, the flow in an industrial combustor can be treated as an optically thick turbulent flow in chemical equilibrium. Such flows scale exactly for similar geometries and wall conditions. Main flow departures from this scaling are small and can generally be treated as either scaling corrections or accepted as experimental errors. Wall effects do not scale as directly but may be compensated for by wall temperature changes if important. This approach results in the simple scaling laws, given in the next section, which allow realistic combustor scaling. These scaling laws provide for the practical scaling of the dominant combustor flow features for gas, oil, and coal fired units and for simple extrapolation, which requires further correction only for thin gas radiation effects, of contaminant formation to full size units.

2. SCALING CRITERIA AND SIMILARITY LAWS

A list of the conditions for similarity is given below. These are sufficient conditions of which some may not be necessary and some may be altered to achieve certain desired scaling results. Items 1 to 9 are operating variables to be kept equal for subscale model and fullscale prototype. Item 10 concerns geometric scaling, and item 11 concerns particle size scaling in oil and coal fired units. Items 12 to 15 are idealized assumptions of the physical processes.

1. Fuel composition
2. Oxidizer composition
3. Fuel temperature
4. Oxidizer temperature
5. Pressure
6. Equivalence ratio
7. Inlet velocities
8. Wall temperatures
9. Inlet turbulence levels
10. Geometries are similar between model and prototype
11. With particles, their size distribution varies with one-half power of combustor dimension
12. Fuel-oxidizer combustion is limited only by diffusion
13. Molecular processes are unimportant compared to turbulent transport processes
14. Radiation effects are negligible
15. Body forces are negligible

The above conditions for similarity are surprisingly few. In fact, similarity in combustors for laminar flow is much more difficult to achieve as noted in a later section. Of the conditions listed above, the operating variables 1 to 9 can easily be kept the same between model and prototype. Geometric similarity, item 10, can be achieved to a large extent, at least in the important characteristics. Particle size, item 11, certainly can be chosen at inlet. It will be shown in a later section that the particle size will remain scaled throughout the flowfield for oil burning, but an additional scaling condition between burning rate and combustor size is required for coal burning. Only items 12 to 15, which are physical processes occurring within the combustor, may be difficult to control in certain circumstances. Corrections for their effects are discussed in a subsequent section.

From the scaling study, the following results of similarity relations are obtained. Items 1 to 7 correspond to results obtained under the idealized conditions listed above, and items 8 to 10 concern relaxation of the idealized conditions.

1. The velocity components, temperature, pressure, density, and major chemical species are equal at corresponding positions between subscale and prototype.

2. The velocity components, temperature, and density of the particle cloud are equal at corresponding positions.

3. The mass fraction of nitric oxide is directly proportional to the combustor length at corresponding positions. (This scaling rule is affected by the non-ideal effects of radiation, molecular dissipation of turbulent eddies, and non-equilibrium chemistry.)

4. The heat fluxes, shear stresses, and mass diffusion rates are equal at corresponding positions.

5. The effective turbulent viscosity is proportional to the characteristic density ρ_o, velocity u_o, and combustor length L.

6. The source term effect is inversely proportional to the product of ρ_o and u_o in the mass and energy conservation equations and to the product of $\rho_o u_o^2$ in the momentum equations,

and these effects are all directly proportional to L. Hence the effects of these source terms (gravitational force, finite-rate chemical reaction, and thin gas radiation, etc.) on the flowfield can be simulated in subscale models by employing smaller ρ_o and u_o and by taking the dependencies, if any, of the source terms on ρ_o and u_o into account.

7. In oil or coal fired units, the rule of varying the particle size with the square root of combustor length provides for similarity in gas-particle mass, momentum, and energy transfers.

8. The reference velocity u_o need not be maintained equal for subscale and fullscale, as long as the velocity ratios at corresponding boundaries are kept equal and the kinetic energy dissipation and pressure variation are small. The velocity components normalized by u_o are then still similar in the combustors.

9. The reference density ρ_o or the reference pressure p_o need not be maintained equal for subscale and fullscale, as long as the density or pressure ratios at corresponding boundaries and the reference temperature T_o (and hence the ratio p_o/ρ_o) are kept equal. In this case, the local density and pressure normalized by ρ_o and p_o, respectively, remain similar between subscale and fullscale.

10. Radiation, in optically thick conditions, has negligible influence on the scaling of turbulent flowfield and nitric oxide. Under thin gas conditions, however, radiation exerts greater effect on larger combustors and affects the scaling of nitric oxide in a nonlinear manner.

3. DERIVATION OF SCALING RELATIONS

The scaling criteria will be derived from the conservation equations for two-dimensional turbulent flow for simplicity. The results obtained are applicable to three-dimensional flows as well. In this section, attention will be focused on gaseous turbulent diffusion flames. Accounts for two-phase flow, radiation, finite-rate combustion, molecular transports, etc. will be pursued in a subsequent section.

3.1 Governing Equations

The conservation equations governing the flow of a compressible reacting gas can be found in textbooks (e.g., Gosman et al. (1969)). For steady plane or axisymmetric two-dimensional flows, these equations can be written in the form

mass:

$$\frac{\partial}{\partial x}(\rho u) + \frac{1}{y^\sigma}\frac{\partial}{\partial y}(y^\sigma \rho v) = R \qquad (1)$$

x-momentum:

$$\frac{\partial}{\partial x}(\rho u^2 - \tau_{xx}) + \frac{1}{y^\sigma}\frac{\partial}{\partial y}\left[y^\sigma(\rho v u - \tau_{yx})\right] + \frac{\partial p}{\partial x} = F_x \qquad (2)$$

y-momentum:

$$\frac{\partial}{\partial x}(\rho u v - \tau_{xy}) + \frac{1}{y^\sigma}\frac{\partial}{\partial y}\left[y^\sigma(\rho v^2 - \tau_{yy})\right] - \frac{\sigma}{y}(\rho w^2 - \tau_{\theta\theta}) + \frac{\partial p}{\partial y} = F_y \qquad (3)$$

θ-momentum:

$$\frac{\partial}{\partial x}(\rho u w - \tau_{x\theta}) + \frac{1}{y^{2\sigma}}\frac{\partial}{\partial y}\left[y^{2\sigma}(\rho v w - \tau_{y\theta})\right] = 0 \qquad (4)$$

energy:

$$\frac{\partial}{\partial x}(\rho u \tilde{h} + q_x - \tau_{xx} u - \tau_{xy} v - \tau_{x\theta} w)$$
$$+ \frac{1}{y^\sigma}\frac{\partial}{\partial y}\left[y^\sigma(\rho v \tilde{h} + q_y - \tau_{yx} u - \tau_{yy} v - \tau_{y\theta} w)\right] = Q \qquad (5)$$

species:

$$\frac{\partial}{\partial x}(\rho u m_i + j_{ix}) + \frac{1}{y^\sigma}\frac{\partial}{\partial y}\left[y^\sigma(\rho v m_i + j_{iy})\right] = R_i \qquad (6)$$

where $\sigma = 0$ for planar flow and $\sigma = 1$ for axisymmetric flow. The velocity components, u, v, and w are in the directions of x, y, and θ, respectively, which denote the axial, vertical or radial, and azimuthal (for $\sigma = 1$) coordinates, respectively. For rectangular geometry or in the absence of swirl for cylindrical geometry, the θ-momentum equation is not needed since w is then zero everywhere. The symbols ρ, p, $\tilde{h}$, and m_i denote, respectively, density, pressure, specific stagnation enthalpy, and mass fraction of chemical species i. Also, q_α and $j_{i\alpha}$ where $\alpha = x$, y, or θ denote heat flux and diffusion flux of species i, respectively, in the direction α; and τ_{mn} where m, n = x, y, or θ denotes shear stress in the plane perpendicular to the m axis and in the direction parallel to n. The R represents a mass source due to particle vaporization. The F_x and F_y represent momentum sources due to body forces, particle drags, etc.; Q is an energy source accounting for thermal radiation, particle heat transfer, etc.; and R_i is a mass source for species i due to chemical reaction, particle vaporization, etc. These source terms will be left unspecified at this point.

The relations between stagnation enthalpy $\tilde{h}$, enthalpy h, and temperature T are given by

$$\tilde{h} = h + \frac{1}{2}(u^2 + v^2 + w^2) \quad (7)$$

$$h = \sum_i m_i h_i \quad (8)$$

$$h_i = h_{ir} + \int_{T_r}^{T} c_{pi}\, dT \quad (9)$$

where h_{ir} is the reference enthalpy of species i at temperature T_r, and c_{pi} is the constant-pressure specific heat of species i. The equation of state is taken as

$$p = \rho \bar{R} T \quad (10)$$

where $\bar{R}$ is the gas constant of the gaseous mixture. In addition, the following relations may be used:

$$\tau_{xx} = \mu\left[2\frac{\partial u}{\partial x} - \frac{2}{3}\left(\frac{\partial u}{\partial x} + \frac{1}{y^\sigma}\frac{\partial}{\partial y}y^\sigma v\right)\right] \tag{11}$$

$$\tau_{yy} = \mu\left[2\frac{\partial v}{\partial y} - \frac{2}{3}\left(\frac{\partial u}{\partial x} + \frac{1}{y^\sigma}\frac{\partial}{\partial y}y^\sigma v\right)\right] \tag{12}$$

$$\tau_{\theta\theta} = \mu\left[\frac{2\sigma v}{y^\sigma} - \frac{2}{3}\left(\frac{\partial u}{\partial x} + \frac{1}{y^\sigma}\frac{\partial}{\partial y}y^\sigma v\right)\right] \tag{13}$$

$$\tau_{xy} = \tau_{yx} = \mu\left(\frac{\partial u}{\partial y} + \frac{\partial v}{\partial x}\right) \tag{14}$$

$$\tau_{x\theta} = \tau_{\theta x} = \mu\frac{\partial w}{\partial x} \tag{15}$$

$$\tau_{y\theta} = \tau_{\theta y} = \mu y^\sigma\frac{\partial}{\partial y}\left(\frac{w}{y^\sigma}\right) \tag{16}$$

$$q_x = -k\frac{\partial T}{\partial x} + \sum_i h_i j_{ix} \tag{17}$$

$$q_y = -k\frac{\partial T}{\partial y} + \sum_i h_i j_{iy} \tag{18}$$

$$j_{ix} = -\rho D_i\frac{\partial m_i}{\partial x} \tag{19}$$

$$j_{iy} = -\rho D_i\frac{\partial m_i}{\partial y} \tag{20}$$

where μ, k, and D_i denote viscosity, conductivity, and diffusion coefficient of species i, respectively.

The conservation equations given above are strictly valid only for laminar flows. At present, no rigorous and generally successful theory governing turbulent recirculating flows is available. The simplest approach is the one taken by Gosman et al. (1969) which merely replaces the molecular transport coefficients μ, k, and D_i by effective values. One may note that the differential equations for this approach are slightly different from those obtained by taking time-mean values of the conservation equations. For example, in the Gosman approach, the first term in equation (1) is simple $\partial/\partial x(\overline{\rho u})$ where the bar indicates time-mean values. On the other hand, if one takes time-mean of the term $\partial/\partial x(\rho u)$, one obtains $\partial/\partial x(\bar{\rho}\bar{u} + \overline{\rho' u'})$ where the prime indicates fluxtuating quantities. The differences, however, are generally small and Gosman's approach is employed here for simplicity. Furthermore, the discussions here apply to either approach. The expressions for the effective transport coefficients will be specified later.

3.2 Scaling of Flow Properties and Nitric Oxide

The following non-dimensional variables are defined:

$$U = u/u_o, \quad V = v/u_o, \quad W = w/w_o \tag{21}$$

$$H = h/h_o, \quad E = (u^2 + v^2 + w^2)/2h_o \tag{22}$$

$$j^*_{i\alpha} = j_{i\alpha}/\rho_o u_o, \quad \tau^*_{mn} = \tau_{mn}/\rho_o u_o^2, \quad q^*_\alpha = q_\alpha/\rho_o u_o h_o \tag{23}$$

$$p^* = p/p_o, \quad \rho^* = \rho/\rho_o \tag{24}$$

$$\xi = x/L, \quad \eta = y/L \tag{25}$$

where the subscript o refers to a reference value and L is a characteristic length. The governing equations can then be written in the form

$$\frac{\partial}{\partial \xi}(\rho^* U) + \frac{1}{\eta^\sigma}\frac{\partial}{\partial \eta}(\eta^\sigma \rho^* V) = \frac{L}{\rho_0 u_0} R \tag{26}$$

$$\frac{\partial}{\partial \xi}(\rho^* U^2 - \tau^*_{xx}) + \frac{1}{\eta^\sigma}\frac{\partial}{\partial \eta}[\eta^\sigma(\rho^* VU - \tau^*_{yx})] + \frac{p_0}{\rho_0 u_0^2}\frac{\partial p^*}{\partial \xi} = \frac{L}{\rho_0 u_0^2} F_x \tag{27}$$

$$\frac{\partial}{\partial \xi}(\rho^* UV - \tau^*_{xy}) + \frac{1}{\eta^\sigma}\frac{\partial}{\partial \eta}[\eta^\sigma(\rho^* V^2 - \tau^*_{yy})] - \frac{\sigma}{\eta}(\rho^* W^2 - \tau^*_{\theta\theta}) + \frac{p_0}{\rho_0 u_0^2}\frac{\partial p^*}{\partial \eta} = \frac{L}{\rho_0 u_0^2} F_y \tag{28}$$

$$\frac{\partial}{\partial \xi}(\rho^* UW - \tau^*_{x\theta}) + \frac{1}{\eta^{2\sigma}}\frac{\partial}{\partial \eta}[\eta^{2\sigma}(\rho^* VW - \tau^*_{y\theta})] = 0 \tag{29}$$

$$\begin{aligned}&\frac{\partial}{\partial \xi}[\rho^* U(H+E) + q^*_x - \tau^*_{xx} U - \tau^*_{xy} V - \tau^*_{x\theta} W] \\ &+ \frac{1}{\eta^\sigma}\frac{\partial}{\partial \eta}\{\eta^\sigma[\rho^* V(H+E) + q^*_y - \tau^*_{yx} U - \tau^*_{yy} V - \tau^*_{y\theta} W]\} = \frac{L}{\rho_0 u_0 h_0} Q\end{aligned} \tag{30}$$

$$\frac{\partial}{\partial \xi}(\rho^* U m_i + j^*_{ix}) + \frac{1}{\eta^\sigma}\frac{\partial}{\partial \eta}[\eta^\sigma(\rho^* V m_i + j^*_{iy})] = \frac{L}{\rho_0 u_0} R_i \tag{31}$$

where

$$E = (U^2 + V^2 + W^2)/2 u_0^2 h_0 \tag{32}$$

$$p^* = \rho^* \bar{R}\, T / \bar{R}_0 T_0 \tag{33}$$

$$\tau^*_{xx,yy,\theta\theta} = Re^{-1}\left[2\left(\frac{\partial U}{\partial \xi}, \frac{\partial V}{\partial \xi}, \frac{\sigma V}{\eta^\sigma}\right) - \frac{2}{3}\left(\frac{\partial U}{\partial \xi} + \frac{1}{\eta^\sigma}\frac{\partial}{\partial \eta}\eta^\sigma V\right)\right] \tag{34}$$

$$\tau^*_{xy,x\theta,y\theta} = \tau^*_{yx,\theta x,\theta y} = Re^{-1}\left[\left(\frac{\partial U}{\partial \eta} + \frac{\partial V}{\partial \xi}\right), \frac{\partial W}{\partial \xi}, \eta^\sigma \frac{\partial}{\partial \eta}\left(\frac{W}{\eta^\sigma}\right)\right] \tag{35}$$

$$q^*_{x,y} = -Re^{-1}\left[Pr^{-1}\left(\frac{\partial H}{\partial \xi}, \frac{\partial H}{\partial \eta}\right) + \sum_i \left(Sc_i^{-1} - Pr^{-1}\right)\frac{h_i}{h_o}\left(\frac{\partial m_i}{\partial \xi}, \frac{\partial m_i}{\partial \eta}\right)\right] \quad (36)$$

$$\dot{j}^*_{ix,iy} = -Re^{-1}\, Sc_i^{-1}\left(\frac{\partial m_i}{\partial \xi}, \frac{\partial m_i}{\partial \eta}\right) \quad (37)$$

$$Re = \rho_o u_o L/\mu \quad (38)$$

$$Pr = \mu c_p/k \quad (39)$$

$$Sc_i = \mu/\rho D_i \quad (40)$$

$$c_p = \sum_i m_i c_{pi} \quad (41)$$

$$\bar{R} = \sum_i m_i \bar{R}_i \quad (42)$$

where Re is the local Reynolds number based on the characteristic length L and local viscosity μ, Pr is the Prandtl number, and Sc_i is the Schmidt number of species i.

Three important results can be observed from the non-dimensionalized equations at this point. One is that the source terms in the mass, momentum, energy, and species equations are all proportional to L. This means that body forces, radiation, and chemical species production, etc., exert more influence on the flowfield for larger combustors. If these sources (R, F_x, F_y, Q, and R_i) can be made inversely proportional to L, then the effects of source terms become independent of combustor size. This can be achieved, indeed, under certain circumstances. For example, as it will be shown in a later section, the particle drag on the fluid can be scaled inversely with L by employing smaller particles for subscale models.

The second important result is that if the source terms are either negligible or made independent of L, and if the boundary conditions, the thermal and chemical properties c_{pi} and h_{ir}, and the diffusion numbers Re, Pr, and Sc_i are independent of L, then all the flow variables are independent of L. This means that, under the stated conditions, the flowfields are completely similar for combustors of various sizes; i.e., the properties ρ^*, p^*, U, V, W, H, and m_i are equal at corresponding positions (ξ,η) of various geometrically similar combustors. For combustors containing turbulent diffusion flames, R_i (i = fuel, oxidant, and combustion products) is zero except at the flame front where it becomes infinite. The position of the flame front is similar at corresponding ξ and η for equal stoichiometric fuel-oxidant ratio, and hence R_i is independent of L. Thus, the local mass fractions of combustion reactants and products can be simulated. This occurs because the combustion chemistry is extremely rapid and the primary reaction products which dominate the fluid dynamics are in essential equilibrium. This is not true of contaminants whose rate of formation (NO) or destruction (CO) are kinetically controlled. Nitric oxide (NO), being a trace species, has negligible influence on the flowfield and is considered separately from the flow variables. If the NO concentration m_{NO} is far below the equilibrium value as is generally the case, its formation rate R_{NO} is independent of m_{NO} and equation (31) shows m_{NO} to vary linearly with the geometric size of the combustor.

The third important observation is that under certain circumstances, even some boundary conditions need not be similar in order to produce similar non-dimensionalized properties. For example, in many types of combustors such as power plant boilers, the pressure is practically uniform and the kinetic energy is small compared to thermal and chemical energies. The pressure gradient terms in equation (27) and (28) then disappear. Provided that Re is independent of u_o in addition to L, a condition which will be shown to be valid, and provided that the effects of the source terms on the flowfield are small, the non-dimensionalized flow properties are then independent of u_o. That is, if the reference velocity u_o is different between subscale and prototype, the normalized values of U, V, W, H, and m_i (i = fuel, oxidant, and combustion products) are still similar at corresponding non-dimensionalized positions (ξ,η) between subscale and prototype. It is interesting to observe from equation (31) that nitric oxide concentration m_{NO}, however, is inversely proportional to u_o as well as being directly proportional to L. As an illustration, consider applying the scaling rule to the study of Quan et al. (1972) on nitric oxide formation in the turbulent diffusion flame formed between semi-infinite plane streams of fuel and oxidant. There, the scaling length is the distance downstream, x, and the scaling velocity may be taken as the fuel velocity, u_1. Then, for fixed air-fuel velocity ratio, the scaled nitric oxide mass fraction profile, $m_{NO}\, u_1/x$, across the mixing layer is independent of u_1 or x. This is shown in Fig. 1. Thus even nitric oxide concentration profiles may be simulated by changing the injection velocities in proportion to the scale of the combustor, providing that one remains within flame stability limits, etc.

As another example of changing the boundary condition in scaling, consider changing ρ_o or p_o between model and prototype (but keeping h_o, and hence the ratio p_o/ρ_o, the same), then the non-dimensionalized equations without the source terms are still similar. The advantage of this maneuver is that, by changing the pressure in a model combustor, one may counteract the effect of changing size so that finite-rate chemical reactions, for instance, may be scaled as well as the flow properties.

In view of the large number of parameters associated with combustion problems, it is somewhat surprising that a two-dimensional combustor can be simulated or modeled, at least ideally, with so few restrictive conditions. The success can be attributed mainly to the fact that, in the regions of turbulent flow, the Reynolds number Re does turn out to be independent of

ρ_o, u_o, and L. That is, the effective turbulent viscosity is determined by the flow and is proportional to the density, the convective velocity, and the characteristic dimension. This is the reason for the well known experimental observation on turbulent diffusion flames that the flame length to jet orifice diameter ratio is independent of the jet velocity, density, and orifice diameter. It should be noted, however, that although this length ratio is independent of either the fuel or the oxidant velocity and density, the fuel/oxidant velocity and density ratios themselves must be kept constant in order to achieve similarity in non-dimensionalized boundary conditions. It may also be interesting to note that for laminar flow, the Reynolds number Re is, in contrast to turbulent flow, directly proportional to ρ_o, u_o, and L. Thus, for example, if a model of one-tenths of the prototype size is used, then the velocity must be increased by a factor of ten in order to keep Re the same! At least in this sense, then, a turbulent combustor is easier to model than a laminar combustor.

Of course, even a turbulent combustor contains regions of laminar flow near the walls and the dissipation of turbulent eddies, which has been shown by Quan, et al. (1972) to have a dominant influence on the amount of nitric oxide formed, involve molecular processes. Corrections and additions to the above scaling relations in order to account for the molecular processes, as well as for the source terms due to two-phase flow, etc., are discussed in a later section. In the remaining parts of the present section, the scaling of the effective turbulent viscosity and the application of boundary conditions will be discussed.

3.3 Turbulent Transport

The scaling of effective turbulent viscosity will be analyzed for three commonly employed and representative models of turbulent flows. It will be shown that the viscosity is proportional to the characteristic density ρ_o, velocity u_o, and length L; and that the proportionality coefficient, and hence the Reynolds number Re as defined by equation (38), is a function of only the normalized boundary conditions and the normalized positions (ξ,η) and is thus independent of ρ_o, u_o, and L. In regions of turbulent flow, the effective turbulent Prandtl and Schmidt numbers, Pr and Sc_i, are essentially invarient between model and prototype and hence will not be discussed further.

Consider the expression for the effective turbulent viscosity given by Gosman et al. (1969) for turbulent diffusion flames in recirculating flows:

$$\mu = K D^{2/3} W^{-1/3} \rho^{2/3} (\dot{m}_F V_F^2 + \dot{m}_A V_A^2)^{1/3} \tag{43}$$

where K is a constant, D the combustion chamber diameter, W the chamber length, $\dot{m}$ a mass flow rate, and V the velocity; the subscripts F and A denote conditions at the fuel and oxidant inlets, respectively. Taking ρ_F, and V_F, and D to be the characteristic density ρ_o, velocity u_o, and length L, respectively, one obtains

$$\mu = K \rho_o u_o L \left(\frac{4}{\pi}\frac{W}{D}\right)^{-1/3} \left(\frac{d}{D}\rho^*\right)^{2/3} \left(1 + \frac{\dot{m}_A}{\dot{m}_F}\frac{V_A^2}{V_F^2}\right)^{1/3} \tag{44}$$

where d is the diameter of the fuel inlet orifice. For combustors of similar geometry, the ratios W/D and d/D are constant; and for similar boundary conditions, the mass flow ratio $\dot{m}_A/\dot{m}_F$ and the velocity ratio V_A/V_F are also constant. Hence the Reynolds number, $\rho_o u_o L/\mu$, is independent of ρ_o, u_o, and L as postulated and varies only with ρ^* which is similar at corresponding locations of model and prototype.

Consider another common model of effective turbulent viscosity μ, namely, the mixing-length theory for parabolic or boundary layer flow. Here,

$$\mu = \rho \ell^2 \partial u/\partial y \tag{45}$$

where ℓ is the mixing length given by

$$\ell = c x \tag{46}$$

where c is a mixing constant. Equation (45) can be written as

$$\mu = c^2 \rho_0 u_0 L \rho^* \xi^2 \partial U/\partial \eta \tag{47}$$

Since ξ^2 and $\partial U/\partial \eta$ are similar between model and prototype, the similarity requirement that $\mu/\rho_o u_o L$ be independent of ρ_o, u_o, and L is again satisfied.

As a third illustration, consider the approach of Gosman et al. (1969) in which μ is given by

$$\mu = \rho k^{1/2} \ell C_\mu \tag{48}$$

where c_μ approaches a constant for highly turbulent flow, and k and ℓ denote the turbulence kinetic energy and the turbulence length scale, respectively. In this approach, k and ℓ are assumed to be governed by differential equations containing convection, diffusion, and source terms. Examination of their equations show that the ratios k/u_o^2 and ℓ/L are independent of ρ_o, u_o, and L for highly turbulent flow. Hence equation (48), written in the form

$$\mu = \rho_0 u_0 L \rho^* k^{*1/2} \ell^* C_\mu \tag{49}$$

where $k^* = k/u_o^2$ and $\ell^* = \ell/L$, shows that $\mu/\rho_o u_o L$ is also independent of ρ_o, u_o, and L for this method of approach. It is believed that any rigorous turbulence model will yield this scaling relation and the above scaling is thus universal.

3.4 Boundary Conditions

In the elliptic differential equations governing recirculating flow, the values of the gradients of U, V, W, H, m_i, and ρ^* or p^* must be prescribed at all boundaries. To achieve similarity, these boundary conditions must be equal at corresponding positions of ξ_b and η_b between subscale and fullsccale, where the subscript b denotes boundary positions.

For diffusion flames where the fuel and oxidant are injected separately into the combustion chamber, similar boundary conditions imply that at the inlet the fuel-oxidant ratios of velocities, temperature or enthalpy, and density or pressure must be maintained invarient between subscale and fullscale. The normalization values of u_o, h_o, and ρ_o or p_o may be chosen to be the velocity, enthalpy, and density or pressure, respectively, of either the fuel or oxidant stream. As indicated earlier, under the conditions that the pressure variation is small and the kinetic energy dissipation is negligible, u_o need not be equal between subscale and fullscale to achieve similarity. Also, ρ_o and p_o need not be kept the same as long as h_o is.

If a k-and-ℓ type of turbulence model is used to evaluate μ, then the differential equations for k and ℓ require additional boundary conditions. Similarity requirement shows that k/u_o^2 and ℓ/L must be similar between subscale and fullscale at corresponding boundary positions.

4. SOURCE TERMS AND MOLECULAR TRANSPORT

The source terms in the non-dimensionalized momentum, energy, and species equations are all proportional to L, i.e., the source term effects on the flow properties are greater for larger combustors. The source terms due to particle-gas interaction, gravitational forces, finite-rate chemistry, and thermal radiation are discussed in this section. Accounts for laminar or molecular processes and other factors that may influence nitric oxide scaling are also discussed.

4.1 Oil and Coal Combustion

For the particle phase, the conservation equations have the following form

$$\frac{\partial}{\partial x}(\rho_p u_p) + \frac{1}{y^\sigma}\frac{\partial}{\partial y}(y^\sigma \rho_p v_p) = -R_p \tag{50}$$

$$\frac{\partial}{\partial x}(\rho_p u_p^2) + \frac{1}{y^\sigma}\frac{\partial}{\partial y}(y^\sigma \rho_p v_p u_p) = -F_{px} \tag{51}$$

$$\frac{\partial}{\partial x}(\rho_p u_p v_p) + \frac{1}{y^\sigma}\frac{\partial}{\partial y}(y^\sigma \rho_p v_p^2) - \frac{\sigma}{y}\rho_p w_p^2 = -F_{py} \tag{52}$$

$$\frac{\partial}{\partial x}(\rho_p u_p w_p) + \frac{1}{y^{2\sigma}}\frac{\partial}{\partial y}(y^{2\sigma} \rho_p v_p w_p) = 0 \tag{53}$$

$$\frac{\partial}{\partial x}(\rho_p u_p \tilde{h}_p) + \frac{1}{y^{2\sigma}}\frac{\partial}{\partial y}(y^\sigma \rho_p v_p \tilde{h}_p) = -Q_p \tag{54}$$

where the subscript p denotes particle phase, and

$$\tilde{h}_p = h_p + (u_p^2 + v_p^2 + w_p^2)/2 \tag{55}$$

$$h_p = h_{pr} + \int_{T_r}^{T} c_{pp}\, dT \tag{56}$$

For simplicity, only one particle size is considered; but the scaling that follows can readily be generalized to particles of distributed size.

Letting

$$U_p = u_p/u_0 , \quad V_p = v_p/u_0 , \quad W_p = w_p/u_0 \tag{57}$$

$$H_p = h_p/h_0 , \quad \rho_p^* = \rho_p/\rho_0 \tag{58}$$

one may write equations (50) to (54) in the form

$$\frac{\partial}{\partial \xi}(\rho_p^* U_p) + \frac{1}{\eta^\sigma}\frac{\partial}{\partial \eta}(\eta^\sigma \rho_p^* V_p) = -\frac{L}{\rho_0 u_0} R_p \tag{59}$$

$$\frac{\partial}{\partial \xi}(\rho_p^* U_p^2) + \frac{1}{\eta^\sigma}\frac{\partial}{\partial \eta}(\eta^\sigma \rho_p^* V_p U_p) = -\frac{L}{\rho_0 u_0^2} F_{px} \tag{60}$$

$$\frac{\partial}{\partial \xi}(\rho_p^* U_p V_p) + \frac{1}{\eta^\sigma}\frac{\partial}{\partial \eta}(\eta^\sigma \rho_p^* V_p^2) - \frac{\sigma}{\eta}\rho_p^* W_p^2 = -\frac{L}{\rho_0 u_0^2} F_{py} \tag{61}$$

$$\frac{\partial}{\partial \xi}(\rho_p^* U_p W_p) + \frac{1}{\eta^{2\sigma}}\frac{\partial}{\partial \eta}(\eta^{2\sigma} \rho_p^* V_p W_p) = 0 \tag{62}$$

$$\frac{\partial}{\partial \xi}[\rho_p^* U_p (H_p + E_p)] + \frac{1}{\eta^\sigma}\frac{\partial}{\partial \eta}[\eta^\sigma \rho_p^* V_p (H_p + E_p)] = -\frac{L}{\rho_0 u_0 h_0} Q_p \tag{63}$$

where

$$E_p = (U_p^2 + V_p^2 + W_p^2)/2 u_0^2 h_0 \tag{64}$$

Here again, if the source terms can be made inversely proportional to L, then the particle properties, like the fluid properties, are seen to be independent of L. This scaling possibility is investigated below.

To consider the particle-gas interaction terms of R_p, F_{px}, F_{py}, and Q_p, the effects of turbulent fluctuations on particles will be neglected. First, consider oil particles in Stokes flow regime (small particle Reynolds number). Since R_p is proportional to the particle number density, which is proportional to ρ_p/r_p^3 where r_p is the particle radius, and to the vaporization rate of a single particle, which is proportional to r_p, one obtains

$$R_p \sim \rho_o \rho_p^* / r_p^2 \qquad (65)$$

Thus, in order to have the right-hand-side of equation (59) independent of ρ_o, u_o, and L, one may choose the particle size such that

$$r_p \sim (L/u_o)^{1/2} \qquad (66)$$

The particle momentum sources, from the work of Marble (1969), may be shown to be

$$F_{px} \sim \rho_o u_o \rho_p^* (U_p - U) \text{ and } u_o U_p R_p \qquad (67)$$

$$F_{py} \sim \rho_o u_o \rho_p^* (V_p - V)/r_p^2 \text{ and } u_o V_p R_p \qquad (68)$$

Since R_p has the form of equation (65), one obtains

$$F_{px},\ F_{py} \sim \rho_o u_o / r_p^2 \qquad (69)$$

Thus, in order to have the right-hand-side of equations (60) and (61) independent of ρ_o, u_o, and L, one needs $(L/\rho_o u_o^2) \sim (r_p^2/\rho_o u_o)$ and this yields the identical relation as equation (66).

Similarly, the particle energy source has the form

$$Q_p \sim \rho_o \rho_p^* (T_p - T)/r_p^2,\ u_o U_p F_{px} + u_o V_p F_{py}, \text{ and } h_o (H_p + E_p) R_p \qquad (70)$$

Since R_p, F_{px}, and F_{py} have the forms of equations (65) and (69), one obtains

$$Q_p \sim \rho_o / r_p^2,\ \rho_o u_o^2 / r_p^2,\ \rho_o h_o / r_p^2 \qquad (71)$$

Equation (71) shows that $Q_p \sim 1/r_p^2$. Although u_o and h_o must remain invarient in order to have a strictly valid scaling law, the contribution to the energy source by the particle drag forces are small in many instances. In these cases, the second term on the right-hand-side of equation (71) need not be considered and, keeping h_o invariant, one obtains from equation (63) the scaling relation of $(L/\rho_o u_o) \sim (r_p^2/\rho_o)$ which yields again the identical relation as equation (66).

Thus, perhaps fortuitously, the scaling law of $r_p^2 \sim L$ satisfies similarity in vaporization, momentum transfer, and energy transfer as well. In addition, if kinetic energy dissipation is negligible, u_o can also be employed for scaling and the rule becomes $r_p^2 \sim L/u_o$. It may be noted that scaling for two-phase flow in laminar boundary layer is not feasible because the convection and diffusion terms there have different scaling lengths.

Two more aspects must be considered for particle scaling. One is that the particle radius must remain scaled as vaporization occurs, i.e., r_p/r_{po} must be independent of L and u_o at given position of ξ, η. The particle radius is governed by

$$u_p \frac{\partial}{\partial x}\left(\frac{4}{3}\pi r_p^3 \bar{\rho}_p\right) + v_p \frac{\partial}{\partial y}\left(\frac{4}{3}\pi r_p^3 \bar{\rho}_p\right) = R_p/n_p \qquad (72)$$

where $\bar{\rho}_p$ denotes the particle bulk density, and n_p is the number of particles per unit volume given by

$$n_p = \rho_p / \frac{4}{3}\pi r_p^3 \bar{\rho}_p \qquad (73)$$

Equations (72) and (73) become

$$U_p \frac{\partial}{\partial \xi}\left(r_p^{*3}\right) + V_p \frac{\partial}{\partial \eta}\left(r_p^{*3}\right) = \frac{R_p L}{\rho_o u_o \rho_p^*} r_p^{*3} \qquad (74)$$

where $r_p^* = r_p/r_{po}$. Since r_{po} is chosen such that $R_p \sim \rho_o u_o/L$, equation (74) shows that r_p^* is indeed independent of u_o and L.

The second aspect to be considered is that of non-Stokes flow. In most regions of oil fired combustors, the particles move in the vapor stream that originates from the droplet surfaces and thus the relative velocities between particles and vapor are small. Consequently, the particle size scaling rule of

$r_p^2 \sim L/u_o$ derived for Stokes flow is a good approximation in the dominant regions. However, if one is primarily interested in simulating the initial region of a combustor where the particles are injected into the air stream and where the relative velocities between particles and air are large, then the source terms for particle vaporization, drag, and heat transfer are all multiplied by a factor of approximately $(1 + 0.276\, Pr_\ell^{1/3} Re_p^{1/2})$ where Pr_ℓ is the Prandtl number based on molecular properties of the gas and Re_p is the particle Reynolds number defined by

$$\begin{aligned} Re_p &= 2\,[(u-u_p)^2 + (v-v_p)^2 + (w-w_p)^2]^{1/2}\, r_p\, \rho/\mu_\ell \\ &= 2\, u_o \rho_o\, [(U-U_p)^2 + (V-V_p)^2 + (W-W_p)^2]^{1/2}\, r_p\, \rho^*/\mu_\ell \qquad (75) \end{aligned}$$

where μ_ℓ denotes molecular viscosity of gas. Thus for moderate particle Reynolds numbers, the scaling relation is given by

$$r_p^2\,(1 + 0.276\, Pr_\ell^{1/3}\, Re_p^{1/2})^{-1} \sim L/u_o \qquad (76)$$

which may be approximated by $r_p^3 \sim L^2 \rho_o/u_o$ for high particle Reynolds numbers.

Having investigated the modeling of oil droplet combustion by scaling the droplet size, it may be interesting to consider solid particles such as coal. Here, the gas-particle momentum and energy transfers are similar to those for oil and hence the particle size scaling still applies. The question concerns the scaling of the combustion rate.

The combustion of coal may be separated into two modes. One is the gasification of volatiles. This is an internal decomposition process which, from Field et al. (1967), may be described by

$$R_p = (C_1/C_2)\,\rho_o\,\rho_p^*\, e^{-C_3/T_p} \qquad (77)$$

where C_1 is the mass fraction of volatile matter in the coal, C_2 is a characteristic decomposition time, and C_3 is a characteristic temperature. Equation (77) shows that R_p is independent of particle size. To scale the right-hand-side of equation (59), one needs

$$C_1/C_2 \sim u_o/L \qquad (78)$$

Thus, to simulate gasification of volatile matter in subscale models, one needs to substitute a different volatile matter of shorter decomposition time and/or to decrease the flow velocity u_o. The scaling requirement given by equation (78) arises, because decomposition is rate-limited and is thus in contrast to the assumption of diffusion-limited combustion which is listed as assumption 12 in Section 2.

The other combustion mechanism of coal is the burning of the char structure. From Davis et al. (1969), one may take the burning rate for a cloud of particles as

$$R_p = \frac{36\, X_{O_2}\, \rho_o\, \rho_p^*}{\dfrac{K_1\, r_p\, T^{1/2} \exp(K_2/T_p)}{f\, p_o\, p^*} + \dfrac{K_3\, r_p^2}{T^{1/2}}} \qquad (79)$$

where K_1, K_2, and K_3 may be considered as fixed constants, X_{O_2} is the mole fraction of O_2 at the edge of the particle boundary layer, and f is the steric factor. The first and second terms in the denominator of equation (79) account for resistances on surface reaction rate and on counter-diffusion rate of CO_2 and O_2 near the surface, respectively. To satisfy scaling of mass transfer, equation (59) requires $R_p \sim \rho_o u_o/L$; and to satisfy momentum and energy transfers, the scaling rule of $r_p^2 \sim L/u_o$ as given by equation (66) is required. The combination requires $R_p \sim \rho_o/r_p^2$. Examination of equation (79) shows that this condition is satisfied if the combustion of char is diffusion-controlled, which is a valid approximation for large particles and/or high pressure. If the surface reaction rate controls, however, then one must either accept the result of $R_p \sim r_p^{-1}$ given by equation (79) as an approximation to the scaling rule of $R_p \sim r_p^{-2}$ or increase p_o or ρ_o such that p_o or $\rho_o \sim r_p^{-1}$ in order to obtain $R_p \sim r_p^{-2}$.

For high particle Reynolds numbers, correction for their effects on the scaling rules may be made in a manner similar to that given for oil.

4.2 Molecular Transport

Molecular processes affect the scaling of turbulent flow in three major respects. One is that heat transfer to the walls are governed by laminar diffusion in the wall regions. Another is that the dissipation of turbulent eddies, which has been shown by Quan et al. (1972) to have a dominant influence on the amount of nitric oxide formed, is governed by molecular processes. The third is that the gas-particle interaction in two-phase flow, which has already been considered, is dependent on molecular properties.

To correct for the heat transfer in the wall regions of a model, one may balance the heat flux through the laminar boundary layer by the turbulent heat flux at the edge of this layer at corresponding positions of ξ, η. That is, $h(T_e - T_w) = (k\partial T/\partial y)_e$ where h and k are the convective heat transfer coefficient and turbulent conductivity, respectively; and the subscripts e and w denote the edge of the laminar layer and wall, respectively. Since $k\partial T/\partial y$ is proportional to $\rho_o u_o$ and independent of L and since h may be represented, for example, by $h \sim (\rho_o u_o)^{0.8} L^{-0.2}$, one obtains

$$T_e - T_w \sim (\rho_o u_o L)^{0.2} \tag{80}$$

Since T_e is similar (i.e., independent of ρ_o, u_o, and L), equation (80) provides a scaling relation for T_w and shows that a subscale model requires higher wall temperatures to keep the temperatures in the turbulent bulk gas region similar to those of the prototype. The 0.2 power in equation (80) may become significant when the model and prototype length ratio is large.

On the molecular dissipation of turbulent eddies, the mechanism is not well established at present. Here, one may merely indicate that no additional requirement for similarity appears for both limiting cases of no molecular mixing and complete mixing of the eddies. The situation is analogous to chemical reaction where no time or length scale is introduced if the flow is either frozen or at equilibrium, but finite-rate process would introduce a time scale.

4.3 Thermal Radiation

Radiation affects the formation of NO in a nonlinear manner, and will be discussed here for the optically thick and optically thin limits, equations for which are given by Vincenti and Kruger (1965).

The thick gas approximation is valid when the radiation mean free path is much smaller than the flame dimensions. In this case, radiation is treated as heat conduction with the conductivity given by

$$k_r = \frac{16\sigma T^3}{3}\sum_j \frac{M_j}{\kappa_{R_j}} \tag{81}$$

where σ is the Stefan-Boltzmann constant, and M_j and κ_{R_j} are the mole fraction and Rosseland mean absorption coefficient, respectively, of species j. The gaseous species from hydrocarbon combustion that participate in radiation are mainly H_2O, CO_2, and CO for which the values of κ_R are given by Abu-Romia and Tien (1967) as functions of pressure and temperature. The ratio of radiation conductivity to turbulent conductivity shows that $k_r/k \sim (\rho_o u_o L\ \kappa_R)^{-1}$ and is generally small except for small combustors. In typical combustors, then radiation in the thick-gas regime need not be considered because radiation conduction is small compared to turbulent conduction.

The thin gas approximation may be applied when the radiation mean free path is much greater than the flame dimensions. Here, radiation is treated as an energy sink in the energy conservation equation with

$$Q_r = -4\sigma T^4 \sum_j M_j \kappa_{p_j} \qquad (82)$$

where κ_{p_j} is the Planck mean absorption coefficient of species j. Values of κ_{p_j} are also given by Abu-Romia and Tien (1967), and vary with temperature and are proportional to pressure. To have the source term in equation (30) independent of ρ_o, u_o, and L, one needs $\kappa_p \sim \rho_o u_o h_o/L$. Since κ_p is proportional to p_o and hence ρ_o, scaling of thin gas radiation is achievable by employing $u_o \sim L$.

The potential effect of radiation on NO formation has been assessed, and the differences in flame temperature history are shown in Fig. 2. This configuration corresponds to the sample problem investigated by Quan et al. (1973) for nitric oxide formation in recirculating flows without radiation. In the absence of radiation, the calculated results show that the combustor of 32 ft in length forms 327 ppm of NO, that a subscale combustor of 3.2 ft in length forms 32 ppm of NO, and that the turbulent flowfields of these two combustors are similar. Thus, the scaling relations for both the flowfield and NO production are observed. With thick-gas approximation, radiation is found to have negligible effect on the flowfield and NO production. With thin-gas approximation and considering each gas element only to emit radiation and not to absorb any, however, radiation is found to have a strong influence on the temperature field and, consequently, NO production; although its effect on the velocity field is still small. For the larger combustor, NO is reduced from 327 ppm to 71 ppm; whereas for the smaller combustor for which the effect of thin-gas radiation is smaller, NO is reduced from 32 ppm to 23 ppm. The effect of thin-gas radiation on the flame temperature distribution is illustrated in Fig. 2. Thus if a combustor is optically thin or if the subscale combustor is optically thin while the fullscale combustor is optically thick, radiation differences between model and prototype will cause nonlinear NO scaling.

4.4 Gravity and Finite-Rate Chemistry

Gravitational forces are proportional to $\rho_o g$. For absolute similarity, equations (28) and (29) require $Lg \sim u_o^2$. In industrial combustors, gravitational effects are generally negligible and gravitational scaling is generally unimportant.

Finite-rate kinetics may be simulated, according to the source term in equation (31), by requiring that $R_i \sim \rho_o u_o/L$. Thus if the species production rate R_i is independent of density ρ_o, one may simply take $\rho_o u_o \sim L$. If R_i is dependent on pressure p_o or density ρ_o, then one may change the pressure such that $R_i/\rho_o \sim u_o/L$. In the case of NO formation, if the NO concentration is low so that R_i is independent of NO, no change in operating condition is necessary and equation (31) shows that one may simply scale the NO concentration in direct proportion to L except for radiation effects.

Besides radiation, there are other factors which may render the scaling of NO with combustor length nonlinear. If NO is near equilibrium or if there is significant conversion of NO to NO_2, then R_{NO} is a function of m_{NO}, and thus m_{NO} does not vary linearly with L. In two-phase flow, fuel nitrogen effects may become important, e.g., there may be a certain fixed amount of NO formed due to fuel nitrogen regardless of combustor size. The kinetics of fuel nitrogen conversion is not well known; but if it is found that a fixed amount of fuel

NO is formed, then one may simply subtract this amount and scale the remainder of the NO. Keeping the total NO level high also tends to minimize the fuel nitrogen effect. The question of "prompt NO" is associated with non-equilibrium oxygen concentration near the flame front. As indicated in the preceding paragraph, one way of scaling this finite-rate chemistry effect is to set $u_o \sim L$. However, for small L in subscale, one must be certain that u_o is not so low that the flow becomes laminar or unstable.

5. DISCUSSION AND SUMMARY

The reason that turbulent flowfields can be scaled in geometrically similar combustors is that the turbulent transport coefficients are proportional to density ρ_o, velocity u_o, and geometric dimension L. As a result, the ratio of diffusive transport to convective transport becomes independent of ρ_o, u_o, and L. This is the reason that, for example, the flame length to jet diameter ratio in turbulent diffusion flames does not vary with jet diameter, density, or velocity as long as the air-fuel density and velocity ratios are kept constant.

The effects of the source terms in the conservation equations are all proportional to L and inversely proportional to $\rho_o u_o$. Hence one may scale the source terms by simply requiring $\rho_o u_o \sim L$. In modeling, it may not be practical to change ρ_o, and the range of u_o that may be modified may also be limited by the considerations of flame stabilization, flow laminarization, etc. In principle, however, the fact that equal absolute velocity is not a necessary condition for similar flowfield is due to two main reasons. One is that kinetic heating is negligible so that enthalpy is practically independent of velocity. The other, again, is that the diffusive transport coefficients are proportional to velocity. The velocity ratios at corresponding boundary positions of subscale and fullscale must be kept equal, however, in order to achieve similarity in non-dimensionalized boundary conditions. This rule applies to the density ratios as well.

Another interesting aspect which contributes to similarity in turbulent flow is that the shear stress, heat conduction flux, and mass diffusion flux are independent of combustor size. For example, the temperature gradients are much steeper for subscale, but the heat conduction coefficient is much smaller by the same proportion and the net result is that the heat flux at corresponding positions of subscale and fullscale are the same. If the absolute velocities are not the same, however, the fluxes will differ accordingly.

For oil and coal combustion, one may scale the particle-gas momentum and energy transfers by scaling the particle radius as $r_p^2 \sim L$ for fixed $\rho_o u_o$. For oil, this scaling also insures proper scaling of vaporization rate. For coal, additional scaling of the burning rate is required. The $r_p^2 \sim L$ is applicable for Stokes flow regime. For moderately high Reynolds numbers, it becomes $r_p^{1.5} \sim L$.

The particle size scaling for oil provides for equal ratio of all three rates: fuel vaporization, vapor and oxidizer convection, and vapor-oxidizer diffusion. The vaporization-diffusion ratio is important in ensuring a similar combustion mode. For example, if vaporization rate is too slow, oxidizer may diffuse into the cloud of droplets and combustion can occur mainly around the drops instead of mainly near the vapor-oxidizer interface as experimentally observed. In combustors that are only partially similar in geometry, the proper characteristic length L should be chosen as the diameter of the vapor cloud where a diffusion flame occurs.

It is interesting to point out here that for laminar flows, the vaporization-diffusion ratio requires equal r_p/L while the vaporization-convection ratio still requires equal r_p^2/L. Thus, a consistent scaling law does not exist for two-phase laminar boundary layers, whereas it does exist for turbulent boundary layers as well as for inviscid flows since both vaporization-diffusion (for turbulent flow) and vaporization-convection ratios are then satisfied by equal r_p^2/L. It should be mentioned however, that the effects of turbulent fluctuations on gas-particle interactions have not been considered here.

For nitric oxide, since the source term in its continuity equation is scaled with $L/\rho_o u_o$, the NO concentration varies linearly with geometric size for given density and velocity. This conclusion holds for all two or three dimensional flows. This linear relation, however, is modified if radiation and other nonlinear effects become important.

In terms of load or power input to a combustor, NO concentration varies with the square root of load since load varies with the square of the inlet dimension for axisymmetric combustors. Load by itself is not a good scaling parameter, however, because it is a function of two parameters: geometric size and velocity. If the velocity is maintained constant, then nitric oxide increases linearly with one-half power of load. If the geometry is fixed (for same size combustors), however, NO may increase, decrease, or does not change with varying load. These conflicting trends are substantiated by experimental data, and can be accounted for by the trade-off between the effect of residence time and the effect of increasing power output as velocity is increased. In general, the effect of increase in power output, which increases wall temperatures and hence flow-field temperatures, dominates and NO increases with loading. However, this trend certainly should not be attributed to flame length which is independent of velocity for given fuel-oxidizer velocity ratio.

NOMENCLATURE

c_p	specific heat at constant pressure
D	effective diffusion coefficient
E	$(u^2 + v^2 + w^2)/2\ h_o$
F	momentum source
g	gravitational acceleration
H	h/h_o
h	specific enthalpy
$\tilde{h}$	specific stagnation enthalpy
j	mass diffusion flux
j^*	$j/\rho_o u_o$
k	effective heat conductivity
L	characteristic combustor geometric dimension
M	molecular weight
m	mass fraction
Pr	Prandtl number, $\mu c_p/k$
p	pressure
p^*	$p\ /p_o$
Q	energy source
q	heat diffusion flux
q^*	$q/\rho_o u_o h_o$
R	mass source
Re	Reynolds number, $\rho_o u_o L/\mu$
$\bar{R}$	gas constant
r_p	radius of particle
r_p^*	r_p/r_{po}

Sc	Schmidt number, $\mu/\rho D$
T	temperature
U	u/u_o
u	axial velocity
V	v/u_o
v	vertical or radial velocity
W	w/w_o
w	swirl velocity in axisymmetric flow
x	axial distance
y	vertical or radial distance

Greek Letters

η	y/L
θ	azimuthal coordinate
κ_P	Planck mean absorption coefficient
κ_R	Rosseland mean absorption coefficient
μ	effective viscosity
ξ	x/L
ρ	density
ρ^*	ρ/ρ_o
$\bar{\rho}_p$	particle bulk density
τ	shear stress
τ^*	$\tau/\rho_o u_o^2$
σ	= 0 for plane flow, = 1 for axisymmetric flow; Stefan-Boltzmann constant

Subscripts

o	reference point
i	index for chemical species
m	index for x, y, θ
n	index for x, y, θ
NO	nitric oxide
p	particle
r	reference state
x	in x-direction
y	in y-direction
α	index for x, y, θ
θ	in θ-direction

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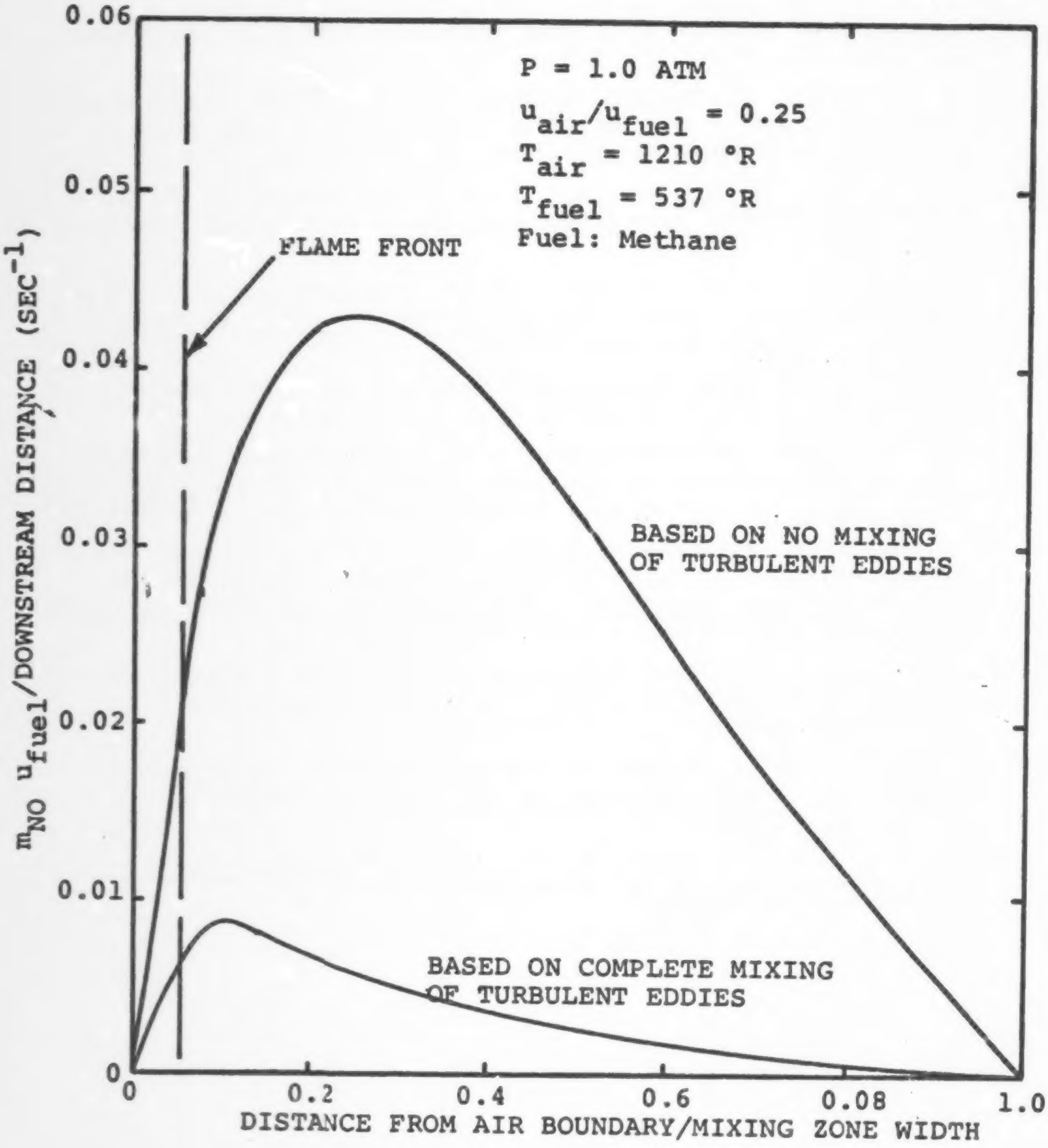

Fig. 1. Scaled Nitric Oxide Concentration Profile in Turbulent Diffusion Flame Between Plane Streams of Methane and Air.

TEMPERATURES (°R) ALONG STOICHIOMETRIC LINE

POINT:	A	B	C	D	E	F
NO RADIATION:	4272	4232	4195	4149	4076	4020
RADIATION, SUBSCALE:	4270	4219	4166	4085	3946	3864
RADIATION, FULLSCALE:	4251	4112	3958	3757	3567	3590

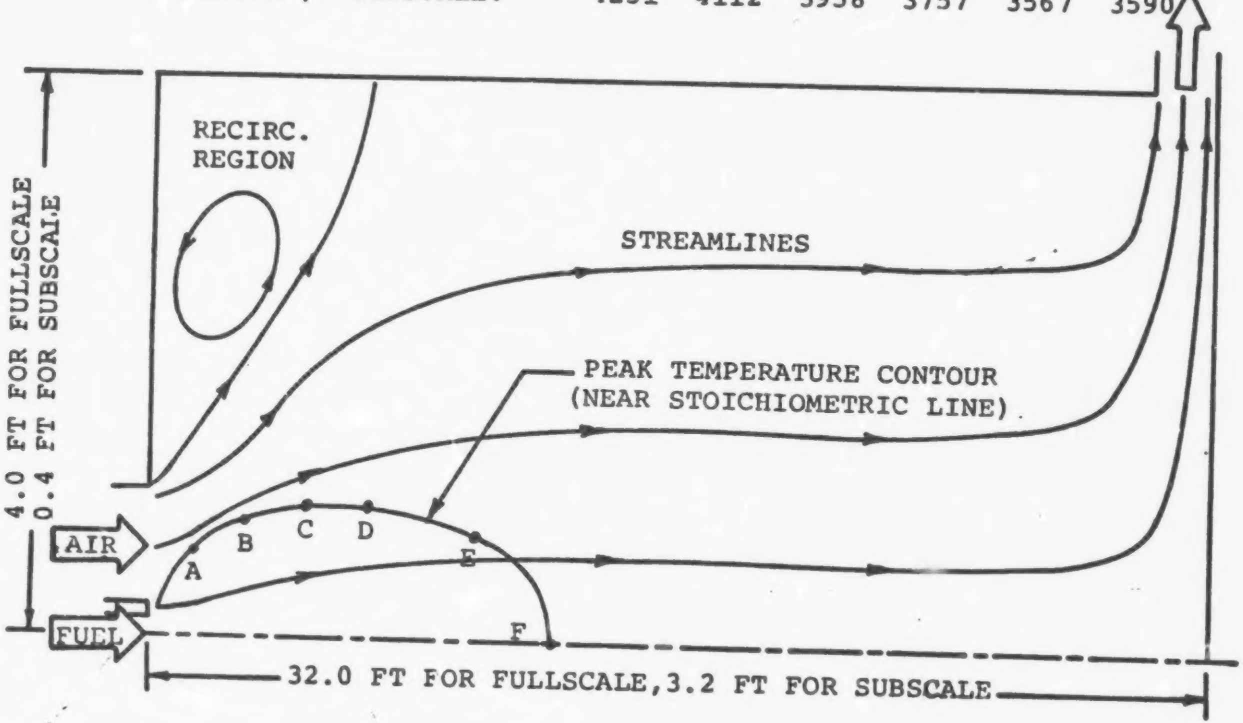
RECIRC. REGION
STREAMLINES
PEAK TEMPERATURE CONTOUR (NEAR STOICHIOMETRIC LINE)
A
B
C
D
E
F
AIR
FUEL
4.0 FT FOR FULLSCALE
0.4 FT FOR SUBSCALE
32.0 FT FOR FULLSCALE, 3.2 FT FOR SUBSCALE

Fig. 2. Effect of Thin Gas Radiation on Flame Temperatures.

FUNDAMENTAL RESEARCH

PART II

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RELATIONSHIP OF BURNER DESIGN TO THE CONTROL OF NO_x EMISSIONS THROUGH COMBUSTION MODIFICATION

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ABSTRACT

The combustion of propane, distillate oil, a 0.3 percent nitrogen oil, and pulverized bituminous coal has been examined in a versatile laboratory furnace. In each case testing was conducted to determine the relationship of burner (and process) parameters to the control of NO_x emissions. The results show that in general propane and distillate oil give about the same NO_x, the 0.3 percent N oil about twice the NO_x, and coal at least 2-1/2 times as much. Increased burner throat velocity and flue gas recirculation were shown to be extremely effective in reducing thermal NO_x, but neither worked very satisfactorily with the high nitrogen oil or coal. Increasing air preheat substantially increased the NO_x emissions from propane and distillate oil and caused lesser increases with the high nitrogen distillate and pulverized coal. Future work will extend the program to natural gas and No. 6 oil and will consider two stage combustion.

This paper summarizes results obtained under ROAP 21ADG-Task 42 (in-house) under the sponsorship of the U. S. Environmental Protection Agency. The work reported herein was completed June 13, 1973.

INTRODUCTION

BACKGROUND

Several groups have recently noted the importance of burner parameters in NO_x formation. Some of the earliest work was done by Wasser et al.[1] in a 3 GPH refractory lined test furnace. Their data indicated that with distillate oil NO_x emissions increase with firing rate, decrease when the excess air is increased from 25 to 45 percent, and are most strongly a function of burner swirl. With the burners at full load, Wasser was able to vary NO from 130 ppm to 480 ppm (no air preheat) by changing only the amount of swirl in the combustion air stream. The data were correlated using cold flow residence time distribution data. From this, it was shown that the large changes in NO were due to changes in primary zone combustion intensity induced by the effect of swirl on the combustion fluid dynamics.

The most comprehensive study of burner parameters to date was conducted by Heap et al.[2] at the International Flame Research Foundation in a 2 x 2 x 6.25 m refractory wall furnace. The variables considered included fuel injector design and position, secondary air velocity, quarl type and angle, burner swirl, and fuel types (gas and coal). Heap found that for natural gas flames when the fuel jet remains on the flame axis, NO emissions increased with increasing swirl.[3] Increasing the combustion air velocity from 25 m/sec (82 fps) to 50 m/sec (164 fps) reduced NO emissions. In natural gas flames where the internally recirculating gases form a closed zone on the flame axis (as with a radial hole injector) NO emissions generally decreased with increasing swirl; however, increasing the combustion air velocity again reduced NO. In all cases the decrease is probably due to the entrainment of cooled product gases.

In coal flames with strong axial fuel jets, Heap found that increasing swirl usually decreased the emission of NO_x. Increased secondary air velocity usually increased emissions. In flames from radial coal injectors (where there is reverse flow on the centerline) the NO_x emissions were essentially independent of swirl. In general, the coal data suggested that any change which spread the pulverized coal jet or increased the O_2/fuel ratio near the injector increased NO_x emissions.[4]

Hemsath et al.[5] investigated the importance of proper burner design for low emissions from large industrial natural gas furnaces and found the key to a low emission burner was reducing the combustion temperatures followed by rapid mixing of the combustion products with the surrounding furnace gases. Seven commercial burners were tested in a refractory lined chamber and based on the results a new "low emission" burner was designed. The NO_x emissions from the commercial burners ranged from near 100 ppm at fuel rich or large (> 50 percent) excess air conditions to over 400 ppm at 7 percent excess air. Emissions from the new low emission burner were 50 to 75 percent lower than those from the conventional burners. While the exact design of the new burner is proprietary, available information indicates that emission reduction is achieved through the use of a very small burner block for ignition stability and very high velocity combustion air (small burner throat). The latter results in significant entrainment of cooler flue products and in effect provides aerodynamic flue gas recirculation.

Shoffstall et al.[6] examined the importance of burner design by testing five different types of natural gas burners. In each case, the effect of excess air, load, fuel injector design, and air preheat temperature on NO_x emissions was determined. Burner/injector pairs, where the fuel jet remained on the axis, gave long luminous flames with low NO_x emissions. Increasing the excess air in these cases increased emissions up to at least 20 percent excess air (4 percent O_2).

Burners with high swirl or radial gas injection had internal reverse flow (of combusted products) on the centerline and short, very intense flames. In these cases NO_x emissions were generally higher than the axial flames and, based on in-flame measurements, nearly all the NO_x was formed very near the burner, many times within the burner block itself. These burners also increased in NO_x output as excess air was increased but peaked much earlier, generally before 15 percent excess air (3 percent O_2). The earlier peak and higher emissions may be due to better fuel/air mixing which results in more rapid (and thereby more intense) combustion.

In the 10-20 percent excess air range increasing air preheat increased NO_x in all cases tested, sometimes by as much as 1 ppm per degree F. As excess air was reduced toward zero the effect lessened. Shoffstall concluded that the most obvious means of reducing NO_x emissions (without lowering air preheat and losing efficiency) was to use either low excess air firing or change to an axial fuel injector.

While the above groups were examining the control of NO_x through burner design, many other organizations were conducting laboratory and full scale testing on the more classical NO_x control techniques: low excess air (LEA) firing, staged combustion (SC), and flue gas recirculation (FGR). Since the status of this work has recently been reviewed in considerable depth[7] it will not be discussed here, except to say that available data indicate that LEA and SC (with its variations) are effective in reducing NO_x from gas, oil, and coal systems. FGR is extremely effective with natural gas flames and to a lesser extent with oil. Unfortunately, none of the techniques are without their problems: FGR is economically unattractive and both LEA and SC could cause flame instability, slagging, and corrosion difficulties in coal-fired systems.

PURPOSE

The purpose of this program is to utilize a versatile laboratory combustor to examine the control of NO_x and other emissions through both burner and combustion modifications. The work is directed at present day fossil fuels; specific goals are to:

(1) Determine what effect burner parameters have on the effectiveness of known NO_x control techniques.

(2) Compare the NO reduction possible through proper burner design to that possible through combustion modifications.

(3) Establish the effect of fuel type on NO_x control.

(4) Investigate novel design ideas for further development under contract funding.

This paper is a status report on the work completed to date on Goals 1, 2, and 3.

Environmental Protection Agency policy is to express all measurements in Agency documents in metric units. When implementing this practice will result in undue costs or lack of clarity, conversion factors are provided for the non-metric units used in a report. Generally, this report uses British units of measure. For conversion to the metric system, use the following conversions:

To convert from	To	Multiply by
^{o}F	^{o}C	5/9 (^{o}F-32)
in.	cm	2.54
gal.	l	3.79
GPH	l/min	0.0632
BTU/hr	Cal/hr	252
ft/sec	m/sec	0.304

EXPERIMENTAL APPROACH

The program is designed to consider present day fossil fuels including the following:

Natural gas
*Propane
*Distillate oil
*Distillate oil doped to 0.3 percent N
No. 6 oil (residual)
*Bituminous coal

The distillate oils were included in the program because together they provide a mechanism for examining the conversion of fuel nitrogen. In each case the oil is identical except that in the latter the nitrogen content has been artificially increased to 0.3 percent (by weight). It has been postulated by Martin[8] and others that any difference in NO_x emissions between the two cases can be directly related to conversion of the fuel nitrogen to NO_x.

In each case the fuel is first chemically characterized and the effect of the following burner (and process) variables on NO_x emissions determined:

*Burner swirl
*Fuel injector design
Wall cooling
*Fuel injector position (in the burner throat or
  at the quarl exit)
*Air preheat (ambient to 600°F)
Firing rate (up to 300,000 BTU/hr)
*Combustion air velocity (45, 100, and 200 ft/sec)

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*Work either completed or already in progress.

Because of time limitations all possible combinations are not investigated. The 280,000 BTU/hr (input), 5 percent excess air, 530°F preheat, 100 ft/sec air case has been selected as a base line. The conditions are then varied parametrically around this.

Once the effect of the burner (and process) parameters on NO_x emissions is established for the normal combustor mode, the following control modes are considered and the process repeated:

*Low excess air (down to 1 percent)
Staged combustion
*Flue gas recirculation

As the asterisks indicate, the experimental work is approximately 50 percent complete at the present time; the mathematical analysis and correlation of the results is just beginning.

This report considers the most significant results to date; namely, the effect of:

(1) Fuel type
(2) Burner swirl
(3) Air preheat
(4) Burner throat velocity
(5) Flue gas recirculation
(6) Throat velocity on the effectiveness of flue gas recirculation

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*Work either completed or already in progress.

EXPERIMENTAL FACILITY

FURNACE DESIGN

The experimental furnace is illustrated in Figure 1. The combustion chamber is vertical with the burner mounted on top. The walls are made of a high temperature plastic refractory and normally run about 2500°F with 530°F air preheat. A 1.5 inch water positive pressure is maintained within the chamber. The chamber is cylindrical with a diameter of ≈ 16 inches and is ≈ 55 inches long. The six observation ports provide good access in two planes and at varying heights for flame observation, photography, and insertion of either a water-cooled gaseous sampling or temperature probe. The burner is designed to accept a variety of injectors for gas, oil, or pulverized coal as fuel and is water cooled. Staged air addition is accomplished by means of water-cooled air injectors inserted around the burner through the furnace top. The point of staged air addition is varied by changing the insertion depth of the injectors.

To cool the combustion gases prior to the flue, a forced air heat exchanger is attached at the bottom of the furnace perpendicular to its center line. It consists of concentric steel cylinders ≈ 16 and 20 inches in diameter and ≈ 75 inches long.

SUPPORT EQUIPMENT

The combustor supporting devices are shown in Figure 2 and are designed to provide a wide choice of operating conditions with optimum individual process parameter control. Under normal operating conditions combustion air is supplied by an ambient temperature main blower through a manifold to the swirl, axial, and primary (coal only) air lines. A high-temperature (600°F) blower forces

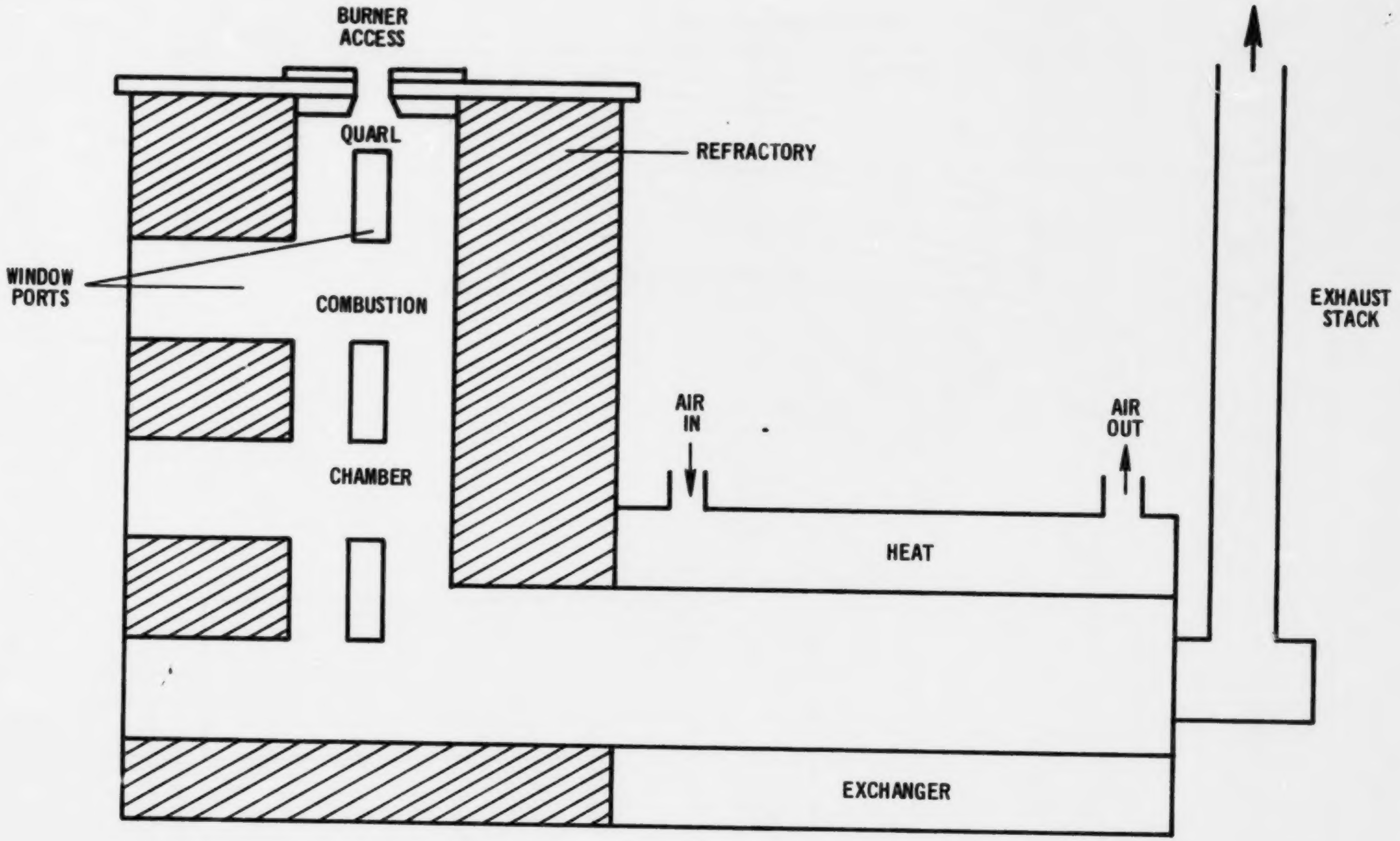
BURNER
ACCESS
QUARL
REFRACTORY
WINDOW
PORTS
COMBUSTION
CHAMBER
AIR
IN
AIR
OUT
EXHAUST
STACK
HEAT
EXCHANGER

Figure 1. Furnace design.

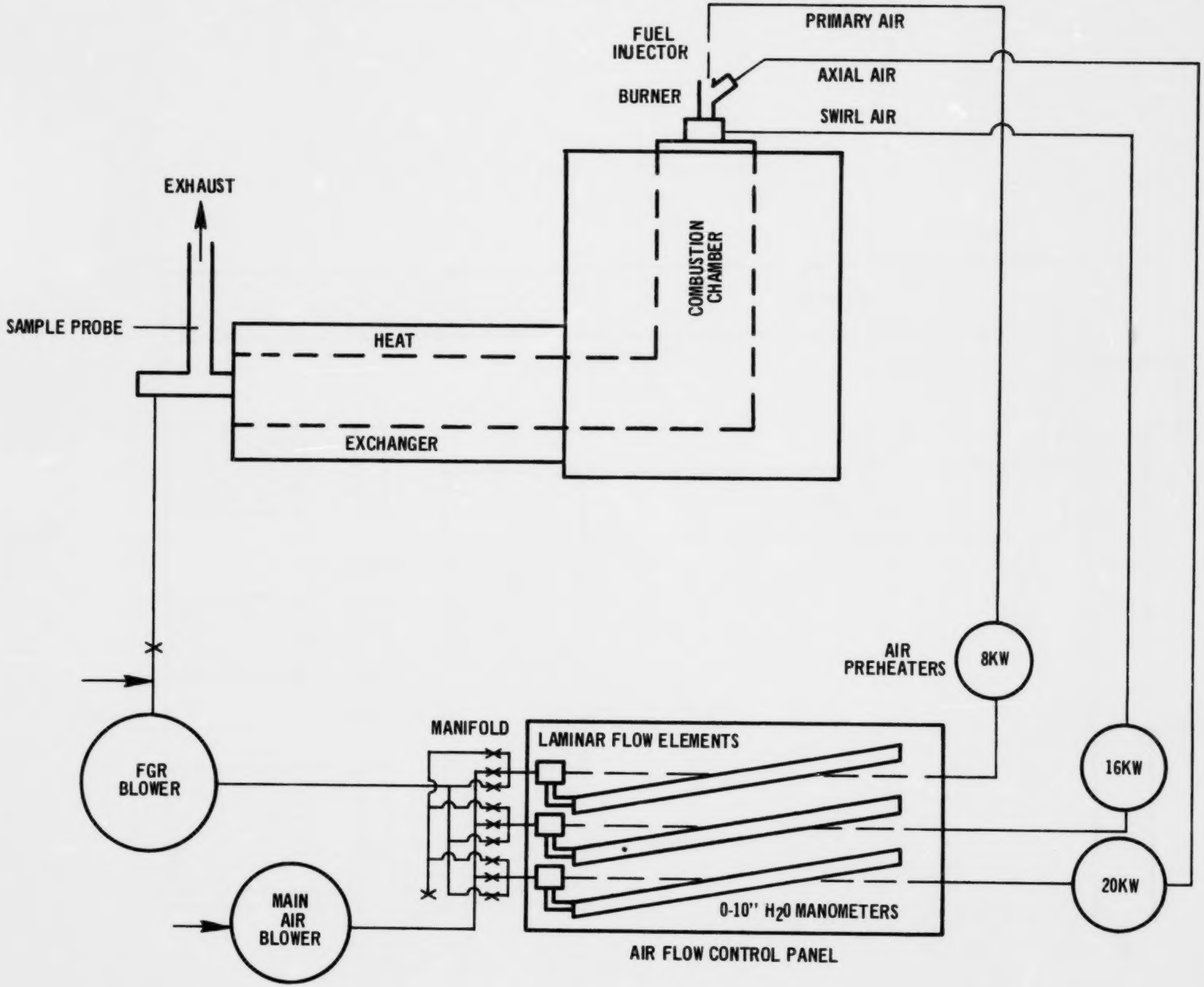
PRIMARY AIR
FUEL INJECTOR
AXIAL AIR
BURNER
SWIRL AIR
EXHAUST
COMBUSTION CHAMBER
SAMPLE PROBE
HEAT
EXCHANGER
AIR PREHEATERS
8KW
16KW
20KW
MANIFOLD
LAMINAR FLOW ELEMENTS
FGR BLOWER
MAIN AIR BLOWER
0-10" H2O MANOMETERS
AIR FLOW CONTROL PANEL

Figure 2. Support equipment.

flue gas (from the exhaust stack) through a second part of the distribution manifold to the proper air line. The third main section of the manifold is connected to a bottled gas supply and provides an Ar/O_2 atomosphere to any of the three air lines. The flow in each of the three air lines (swirl, axial, and primary) is controlled by the manifold valves and is filtered for dust and particulate removal before going through laminar flow elements which are connected to inclined water manometers for measuring the quantities delivered. Each line also has an electric air preheater with proportional controller to provide controlled air temperatures from ambient to 700°F.

FURNACE BURNER

A specially designed water-cooled burner as illustrated in Figure 3 is provided with separate axial air inlet and swirl chamber. The axial air enters through a port angled at ≈ 45 degrees into the center pipe and then passes through straightening vanes. Swirl air enters a vaned swirl chamber via two tangential ports 180 degrees opposed and passes through six 3/4-inch curved swirl vanes as shown in Figure 4. The ID of the burner itself is 2.067 inches; however, nine burner sleeves are provided so that axial momentum can be maintained at air velocities between 45 and 200 ft/sec for a variety of mass flows, air preheats, etc. The burner is fitted with a 35-degree refractory quarl and has an adjustable collar at the top (inlet) to allow for varying the position of the fuel injector relative to the quarl exit.

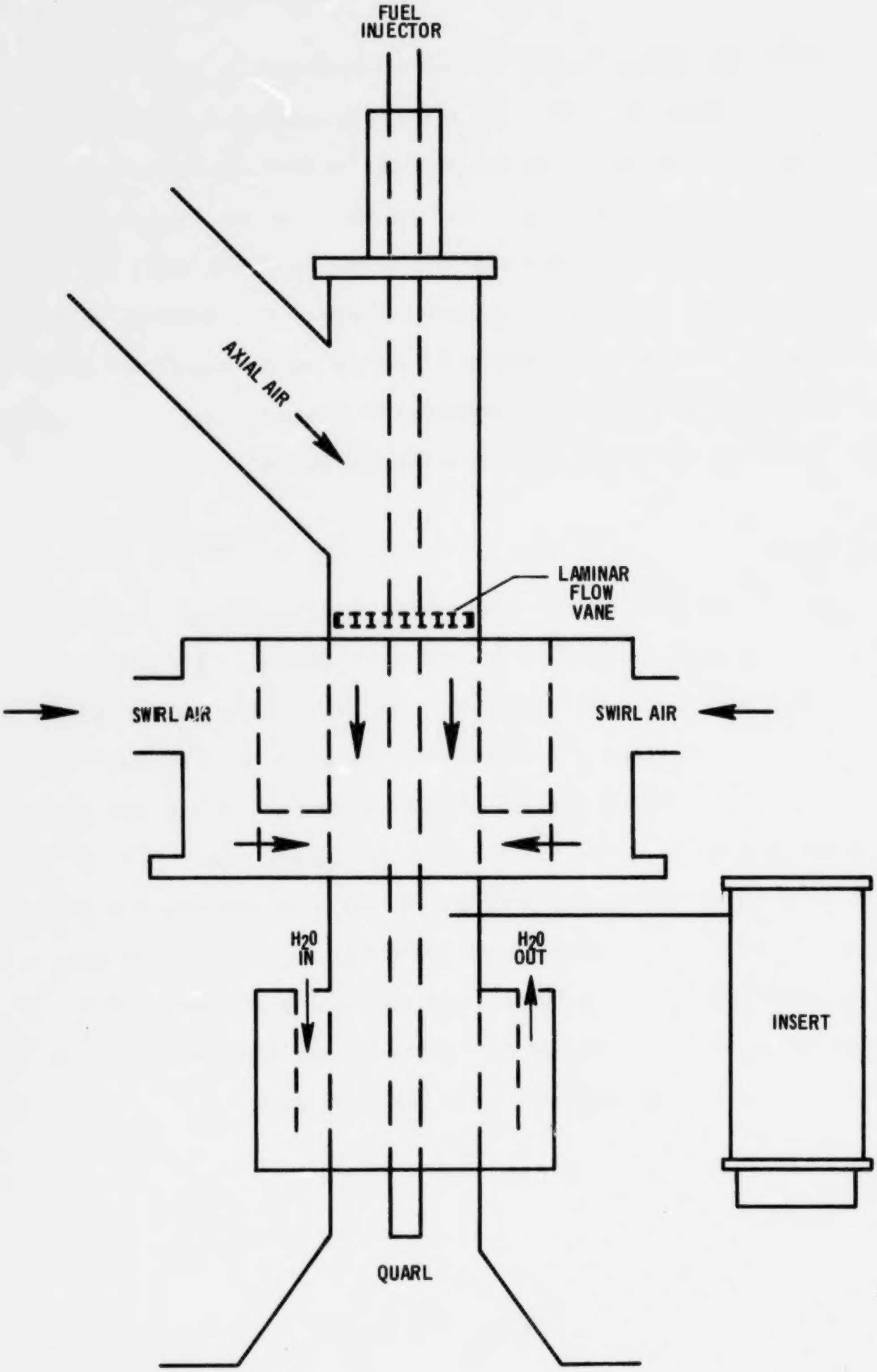
FUEL INJECTOR
AXIAL AIR
LAMINAR FLOW VANE
SWIRL AIR
SWIRL AIR
H_2O IN
H_2O OUT
INSERT
QUARL

Figure 3. Burner.

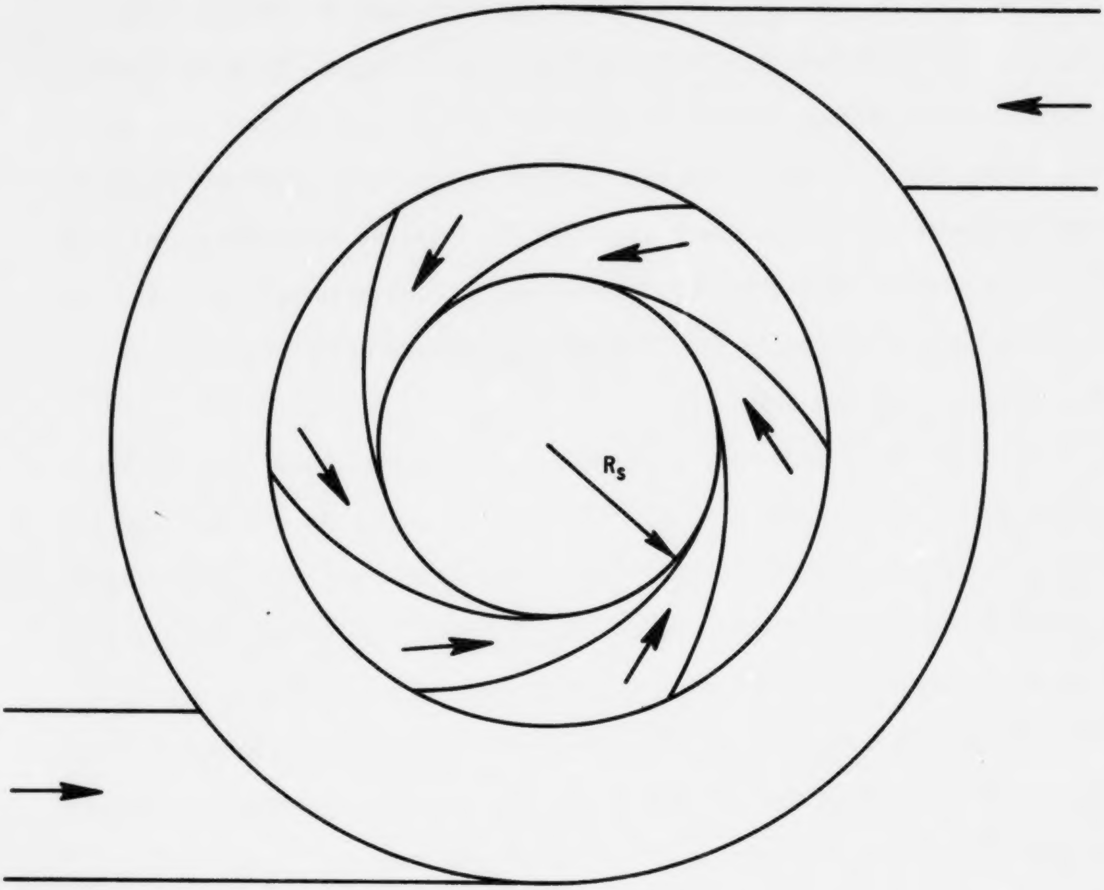

Figure 4. Swirl vanes.

FUEL INJECTORS

A variety of injectors are provided for each type of fuel and are generally characterized as either rapid or slow mixing as shown in Figures 5 and 6. Short bulbous flames are produced by the rapid mixing injectors. The propane radial injector has six equally spaced holes (0.05996 inches in diameter) perpendicular to the axis. The oil injector is a commercial 2.25 GPH nozzle with an 80 degree solid spray angle. The divergent coal injector has three equally spaced (0.2656 inches in diameter) holes angled to distribute the coal away from the axis.

The slow mixing injectors give long predominantly axial flames. The propane axial injector has a single hole (0.1094 inches in diameter) on the axis. The zero degree air atomizing oil nozzle has one hole (0.5937 inches in diameter) angled on the top to prevent clogging. While the rapid mixing injectors produce noticeably more stable flames, all injectors produced stable flames from about 20 to 95 percent swirl under most conditions. The work reported here was all conducted with the rapid mixing injectors since these are more typical of current industrial practice.

STANDARD FUELS

Compositions of the fuels used to date are given in Table 1. The propane is commercial grade and supplied from 100-gal. pressure-regulated cylinders. Flow is controlled by a regulating needle valve and measured on a calibrated gas rotameter. Distillate (#2) oil is delivered by a constant-volume displacement metering pump which is electronically controlled to maintain constant speed. The 0.3-percent N distillate oil is supplied by adding the

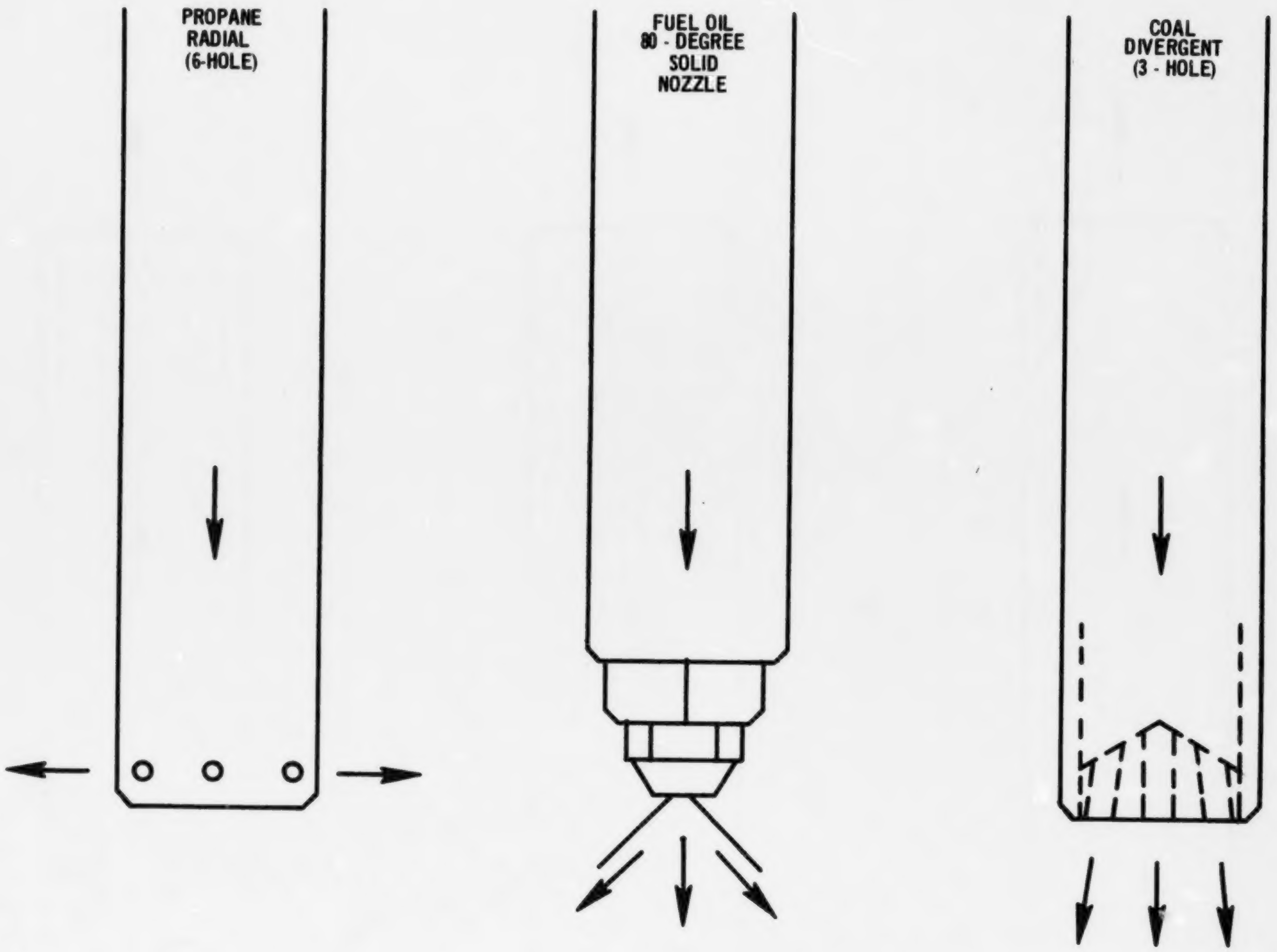
PROPANE
RADIAL
(6-HOLE)
FUEL OIL
80 - DEGREE
SOLID
NOZZLE
COAL
DIVERGENT
(3 - HOLE)

Figure 5. Rapid-mixing injectors.

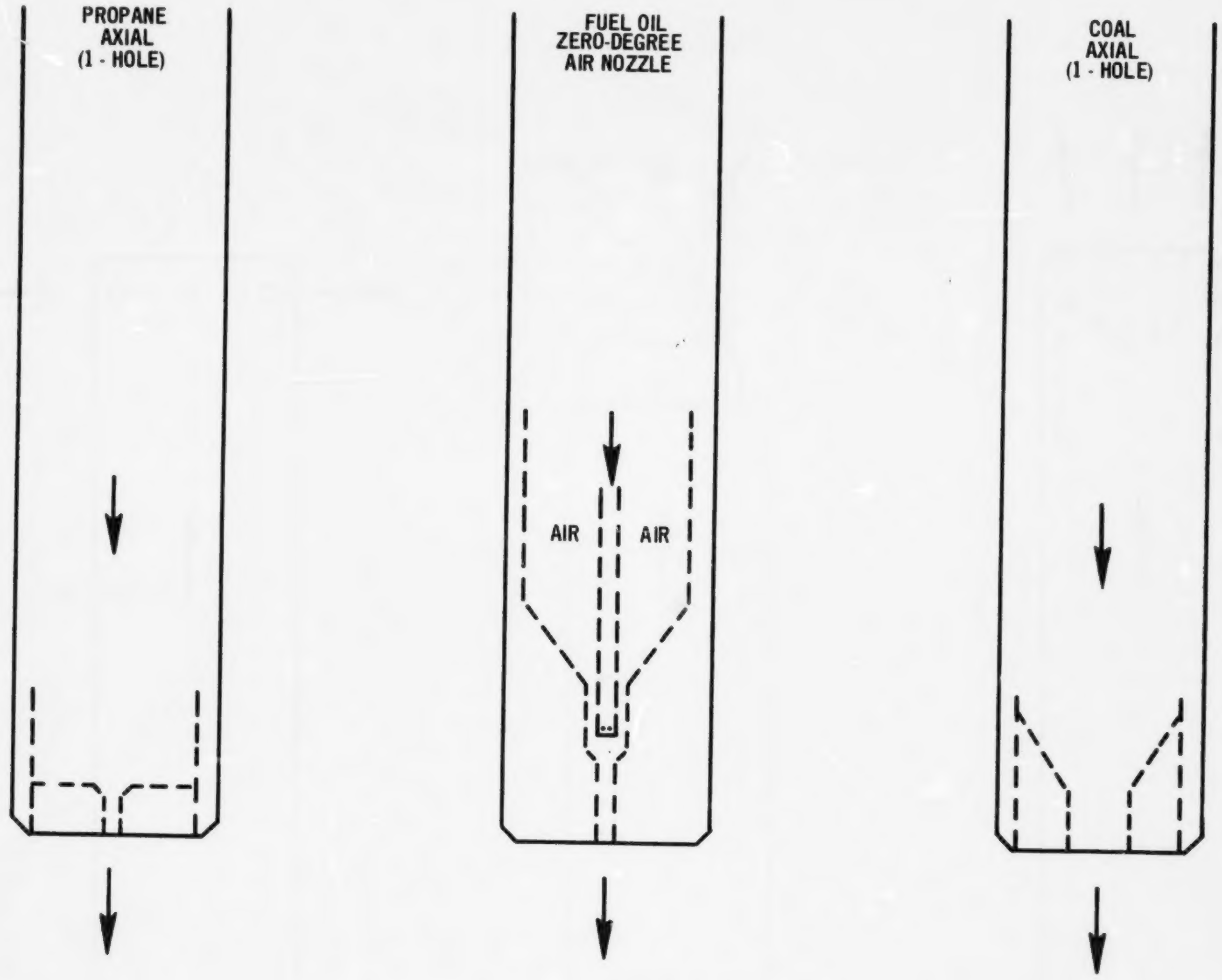
PROPANE
AXIAL
(1 - HOLE)
FUEL OIL
ZERO-DEGREE
AIR NOZZLE
AIR
AIR
COAL
AXIAL
(1 - HOLE)

Figure 6. Slow-mixing injectors.

Table 1. FUEL ANALYSIS

Component	Wt Percent		
	Distillate Oil	High Nitrogen Distillate Oil[a]	Coal
C	87.0	86.7	69.6
H	12.9	12.7	5.3
S	0.22	0.21	3.0
N	<.05	0.31	1.17
O	0.15	0.15	9.6
Ash	0.004	0.004	10.4

Propane: Commercial Grade with > 90% C_3H_8 and < 5% propylene, 2% ethane, 1% isobutane, < 0.5% N-butane.

[a] Doped to 0.31 percent N by the addition of quinoline

appropriate amount of quinoline to the oil supply prior to the combustor. The quinoline is supplied at a constant rate from a special pressurized feed apparatus which is controlled by a micro-needle valve and measured by a calibrated rotameter. (At any given test condition the normal distillate and 0.3 percent N distillate cases are run consecutively to minimize possible errors due to slightly different combustor conditions, preheat temperatures, etc.) Pulverized coal is delivered to the injector along with the primary air by a vibrating hopper screw feeder. Feed rate is controlled by a variable-speed gear motor drive.

ANALYTICAL PROCEDURES

The flue gas sampling system used in this work is shown in Figure 7. It consists of: paramagnetic oxygen analysis; nondispersive infrared analysis for carbon monoxide, carbon dioxide and nitric oxide; flame ionization analysis for unburned hydrocarbons; and chemiluminescent analysis for NO and NO_2 (NO_x). Sample conditioners consist of a dryer (water condenser) and two particulate filters in the main sample line. When burning coal a glass wool trap is placed upstream of the dryer.

The O_2, CO, CO_2, and HC analyzers are further moisure protected by a Drierite ($CaSO_4$) dessicant cannister and molecular sieve traps (Grace SMR 4-635). The NDIR NO analyzer is also Drierite protected. The chemiluminescent unit requires no additional moisture removal. The Drierite cannisters are changed daily and the sieves are replaced as dictated by moisture indicators. The particulate filters are inspected daily and replaced as needed. The glass wool trap is replaced before each coal test. All instruments are calibrated with

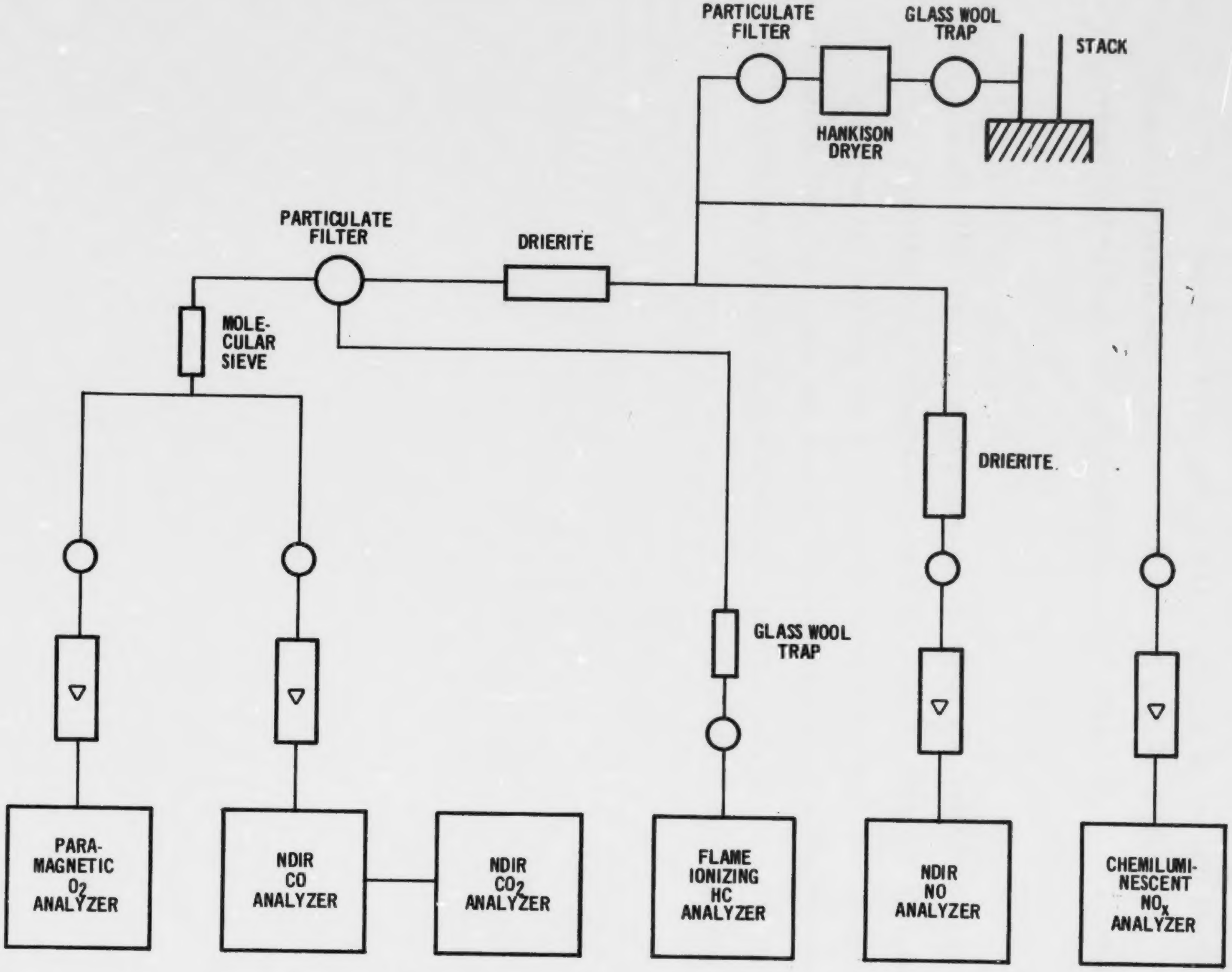
PARTICULATE FILTER
GLASS WOOL TRAP
STACK
HANKISON DRYER
PARTICULATE FILTER
DRIERITE
MOLE-CULAR SIEVE
DRIERITE
GLASS WOOL TRAP
PARA-MAGNETIC O_2 ANALYZER
NDIR CO ANALYZER
NDIR CO_2 ANALYZER
FLAME IONIZING HC ANALYZER
NDIR NO ANALYZER
CHEMILUMI-NESCENT NO_x ANALYZER

Figure 7. Analytical system.

zero and span gas twice daily or before each test if required.

The sample probe is a 3/8-inch diameter quartz tube placed inside the exhaust stack. All sample lines are either stainless steel or Teflon tubing.

SAFETY FACILITY

Flame failure safe operation is assured by a Honeywell R4150 flame safeguard detection system. The flame signal for both gas ignition pilot and main flame is produced by an ultraviolet flame detector. An automatic power-off cutout is provided for both air flow loss and burner cooling water flow loss. In addition a thermal limit switch is provided for any unusual temperature rise at the burner.

DISCUSSION OF RESULTS

DEFINITION OF TERMS

Before considering the results it is important to explicitly define the terminology used. All emissions data are presented as ppm NO, dry reduced to stoichiometric (zero percent excess air). To obtain the mass/heat input the following conversions can be used.

Fuel	To convert to lbs $NO_2/10^6$ BTU multiply by	To convert to gms $NO_2/10^6$ cal multiply by
Propane	0.00108	0.00194
Distillate Oil	0.00108	0.00194
Coal	0.00147	0.00265

All data are reported in terms of a swirl index for common reference. (This is not exactly the same as the swirl number defined by Beer and Chigier[9] because the swirl vanes used in this study were curved to maximize the efficiency of swirl generation.) The swirl index S, is defined as:

$$S = \frac{G_\theta}{G_z \cdot R}$$

where

$$G\theta = \frac{\rho V_s^2 R_s}{A_s}$$

$$G_z = \frac{\rho V^2}{A}$$

and

R = burner throat radius

R_s = radius at swirl vanes

ρ = oxidizer density

$\dot{V}_s$ = volumetric flow rate through swirl vanes

V = total volumetric flow rate

A_s = minimum open area in swirler*

A = burner throat area

(No claim is made for the swirl index as a universal scaling parameter; analysis of this type is just being initiated. It is used here only as a reference basis.)

Flue gas recirculation is defined as follows:

$$\text{Percent FGR} = \frac{\text{wt FGR}}{\text{wt air} + \text{wt fuel}} \times 100\%$$

where

wt FGR = weight of flue gas recirculated

wt air = weight of the combustion air used

wt fuel = weight of fuel burned

FUEL TYPE AND SWIRL

Figure 8 shows the data taken for propane, distillate oil (< 0.05 percent N), high-N (0.31 percent N) distillate, and pulverized coal as a function of swirl. In these and all other tests reported here the propane entered the burner through a six-hole radial injector at a velocity of 300 ft/sec; distillate oil through an 80-degree solid-cone pressure-atomizing nozzle; and coal through a divergent three-hole injector. All the data in Figure 8 were taken at a firing rate of 300,000 BTU/hr, 5 percent excess air, 530°F air preheat, and 100 ft/sec burner throat velocity (combustion air). As the data indicate, the propane and

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*Based on the axial depth of the swirl vanes times the perpendicular distance between vanes at the point of entry into the axial flow.

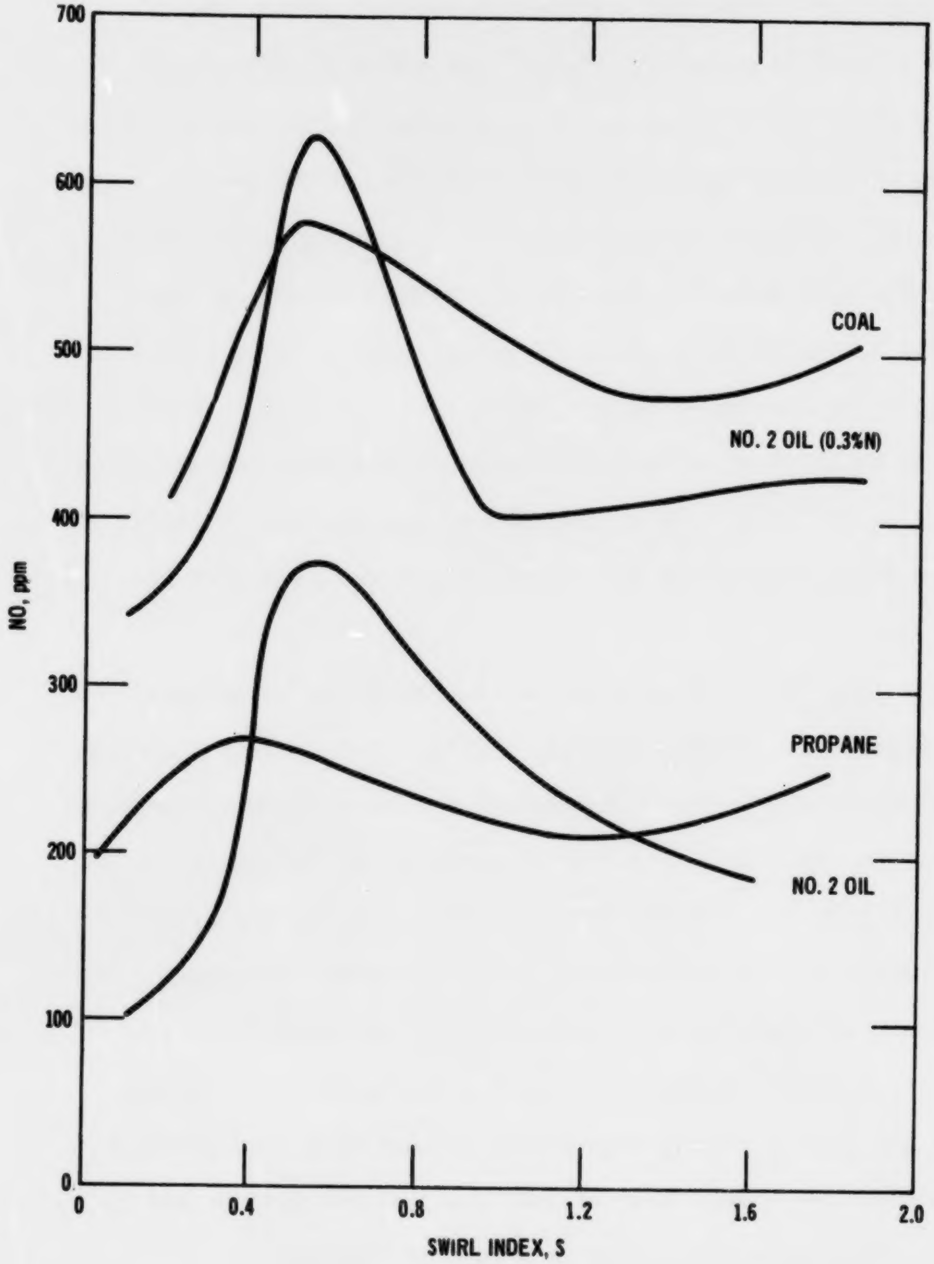

Figure 8. Effect of fuel type and swirl.

distillate oil give nearly identical average emissions; however, the oil is more strongly a function of swirl. The 0.3 percent N distillate has nearly the same form as the previous pair but is about 220 ppm higher over the range, corresponding to about 45 percent conversion of the fuel N (assuming the thermal component can be subtracted directly as proposed by Martin et al.[8]). The coal data are generally the highest of all, as would be expected. The average emission is about 500 ppm of which a large part is almost certainly due to the fuel N in the coal.

At this point no absolute evidence is available regarding the mechanism behind the effect swirl has on each of the curves; however, the following is proposed based on observation of the flames, experience, and work by others.[3,4]

Gas and Distillate Oil: At very low swirl, combustion is delayed farther downstream due to poor fuel/air mixing. This spreads the flame zone over a larger area and reduces the average local flame temperature through both the added bulk of entrained products and increased radiative heat transfer. As the swirl is increased, the fuel/air mixing increases, the combustion zone shrinks (causing increased local temperatures), and the NO_x increases. As the swirl is further increased, the internal reverse-flow zone on the burner axis becomes substantial and begins forcing significant amounts of burned products into the base of the flame. This dilutes the fuel/air mixture and lowers local temperatures by acting as a type of flue gas recirculation.

0.3-Percent N Distillate: The emission data for the high nitrogen distillate follow the normal distillate curve quite closely over the entire swirl range. This indicates that the conversion of the fuel nitrogen is essentially constant (at about 45 percent) and therefore is not a function of swirl in this case.

Coal: The coal data are most easily explained starting at the high swirl setting since even the divergent injector tends to give a fairly axial coal flame.

As the swirl is decreased from its maximum, the NO_x emissions drop slightly then begin a definite rise. Flame photographs reveal that this increase begins at the point where the flame lifts off the injector. At the peak shown in Figure 8, ignition is occurring about 6 inches from the point of injection. Thus, as the emissions are increasing the point of ignition is moving steadily away from the injector. The increase in NO_x here is almost certainly associated with better mixing of coal jets and the combustion air prior to ignition. This, in turn, increases the availability of oxygen and hence the conversion of fuel nitrogen. The decrease after the peak is of little consequence since at this point it is not an acceptable flame for industrial use.

AIR PREHEAT

Figures 9 through 12 show the effect of increasing air preheat from ambient ($100^{o}F$) through $300^{o}F$ to $530^{o}F$ at 100 fps throat velocity and 5 percent excess air for propane, No. 2 oil, 0.3 percent N distillate oil, and coal. As the data in Figures 9 and 10 indicate with gas and distillate oil, increasing air preheat

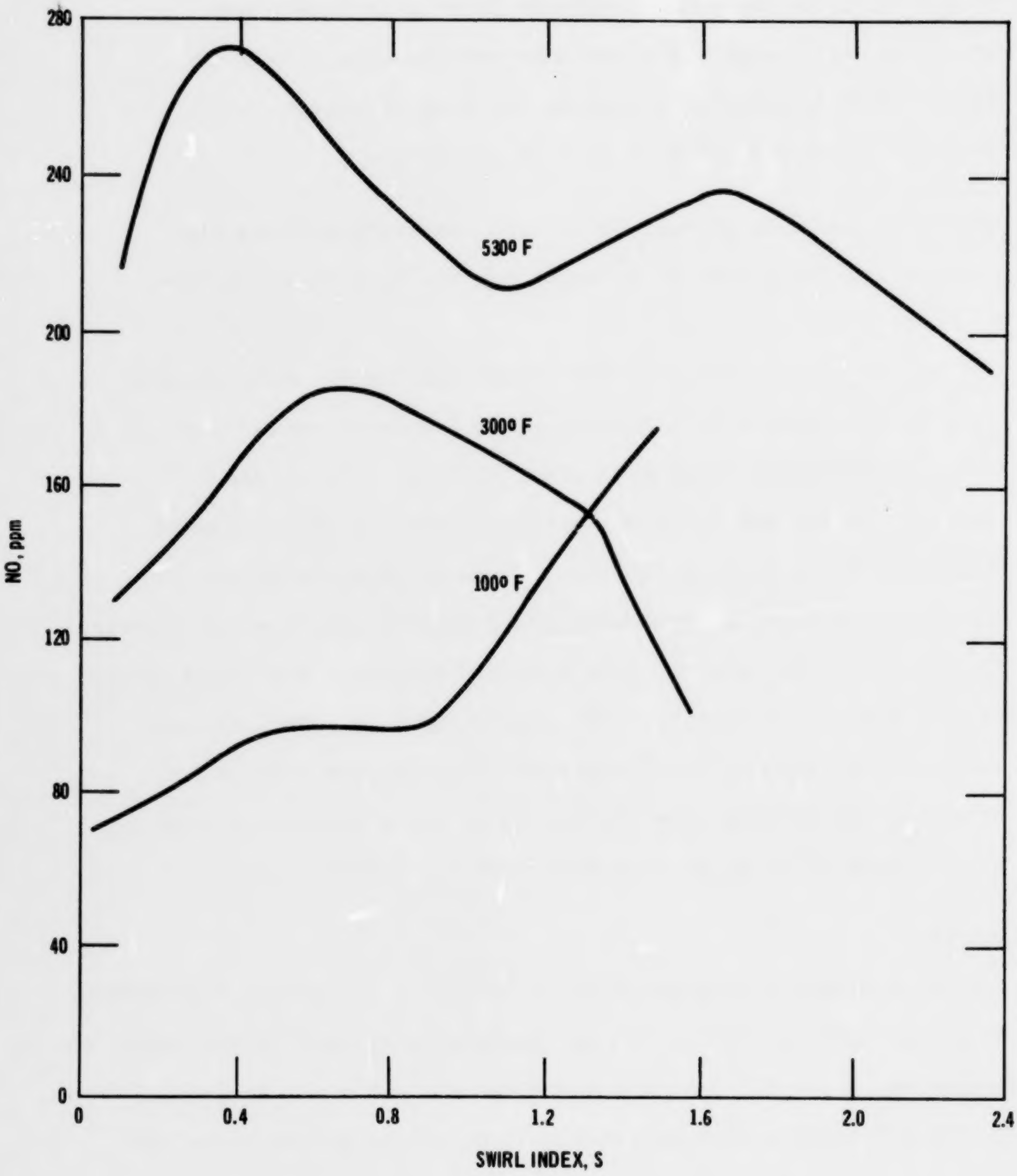

Figure 9. Effect of air preheat using propane.

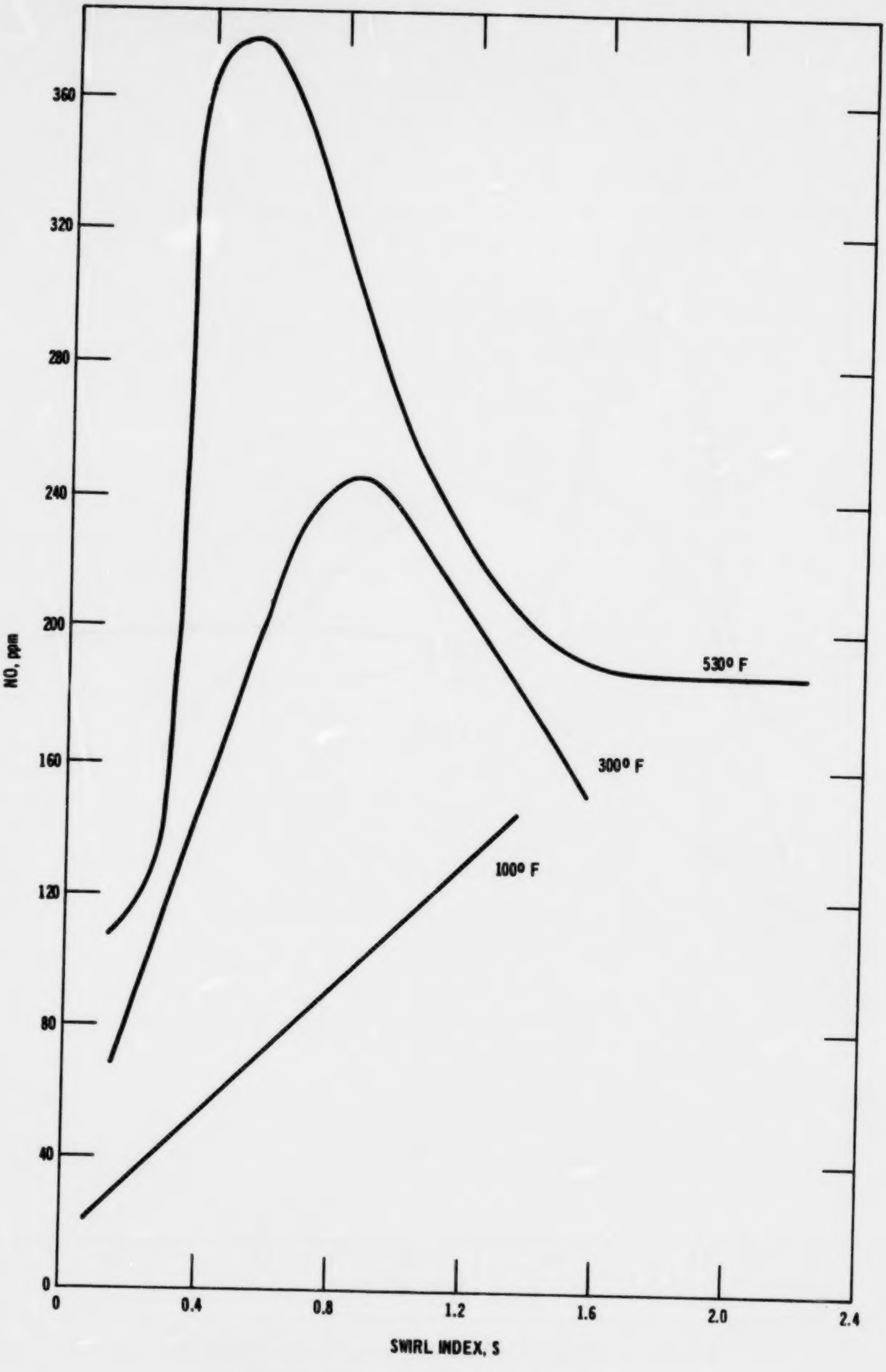

Figure 10. Effect of air preheat using No. 2 oil.

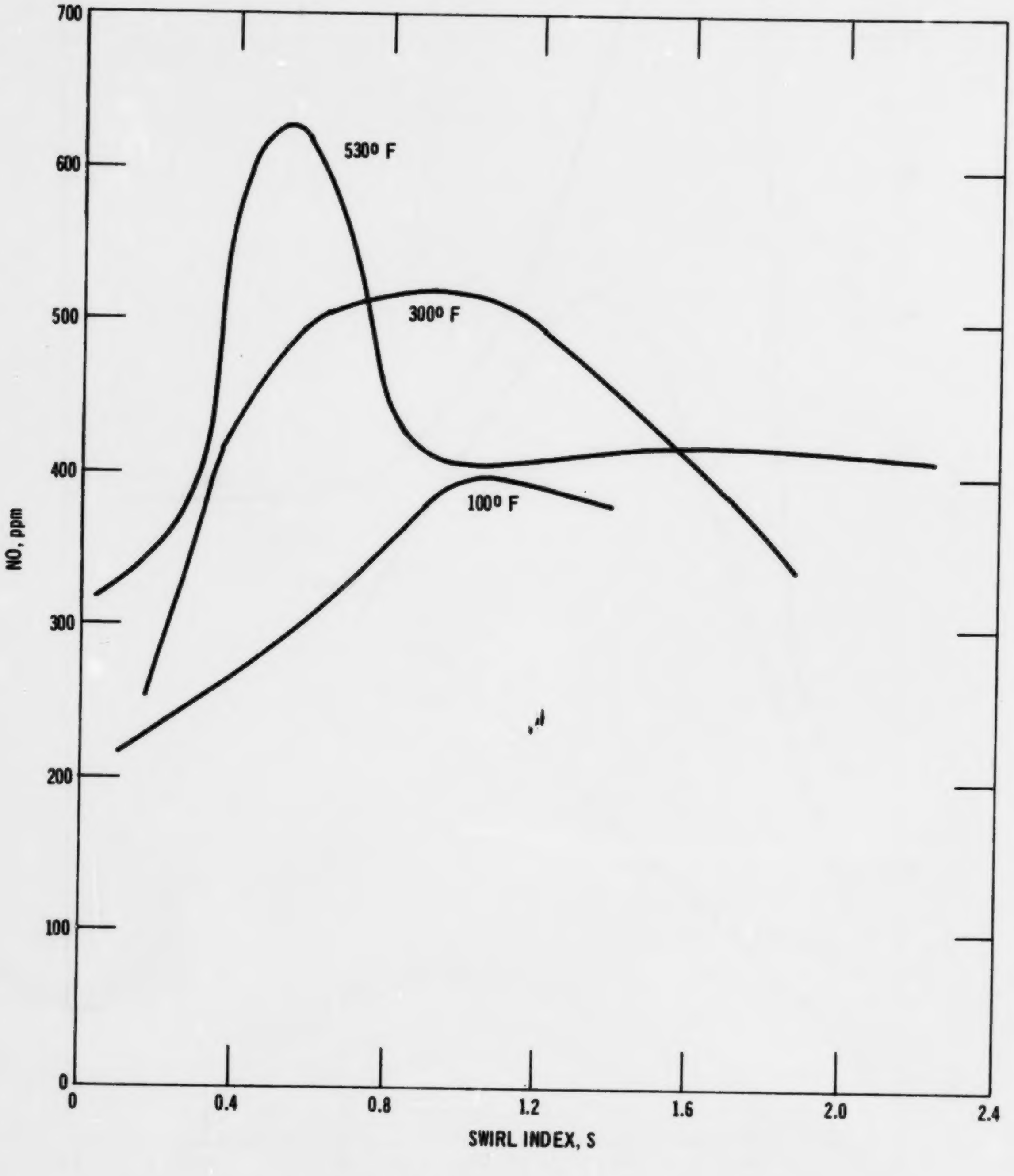

Figure 11. Effect of air preheat using No. 2 oil (0.3% N).

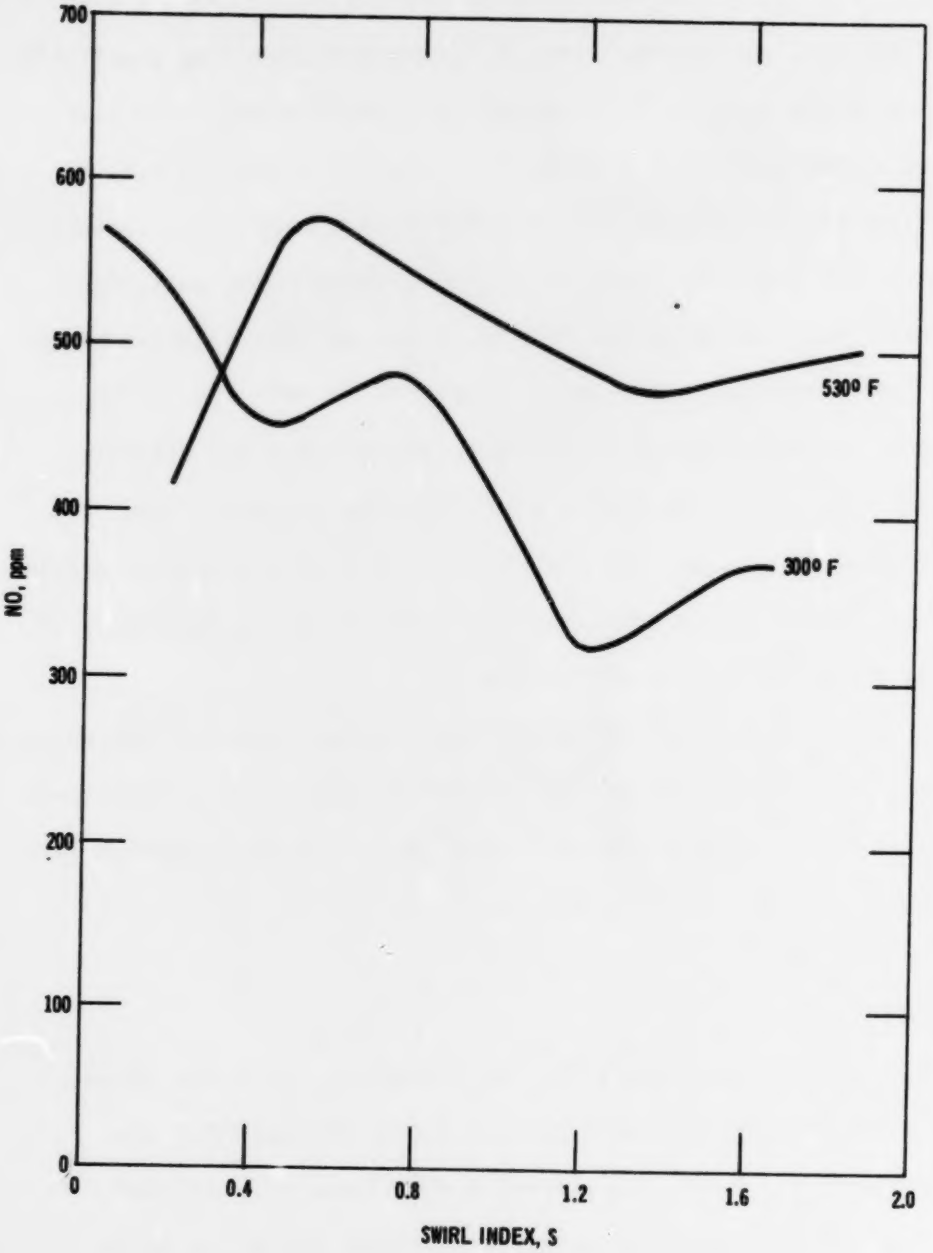

Figure 12. Effect of air preheat using coal.

markedly affects NO_x. This is almost certainly due to an increase in local flame temperature. With both gas and No. 2 oil the preheated cases show a definite peak. (It is certainly possible that the ambient (100°F) cases would have also peaked had higher swirl been available.) Figure 13 shows the peak NO for the distillate oil and propane runs plotted against theoretical (adiabatic) flame temperature for the given case. This figure demonstrates that, for a given air preheat, the peak emissions from No. 2 oil are only slightly higher than from the corresponding propane case. Since all the data lie on the same line (within the experimental error) this suggests that the slightly higher emissions from oil may be due to the intrinsically higher flame temperature (because of a higher C/H ratio) rather than to any type of droplet burning process. There is, therefore, some question as to the importance of droplet burning in the thermal fixation mechanism.

Figures 11 and 12 show that air preheat has a lesser effect on the emission from the 0.3 percent N distillate oil and pulverized coal flames. This tends to support the postulate of Martin et al.[8] that fuel nitrogen conversion is not as temperature sensitive as fixation.

BURNER THROAT VELOCITY

Figures 14 through 17 show the effect of increasing the burner throat velocity from 100 fps to 200 fps (at 5 percent excess air and 530°F air preheat) for propane, No. 2 oil, 0.3 percent N distillate oil, and coal. As the data with gas indicate increased velocity decreases the NO_x by about 60 percent. A similar, but slightly more dramatic, effect is observed with distillate oil. In both cases the increased velocity increases entrainment

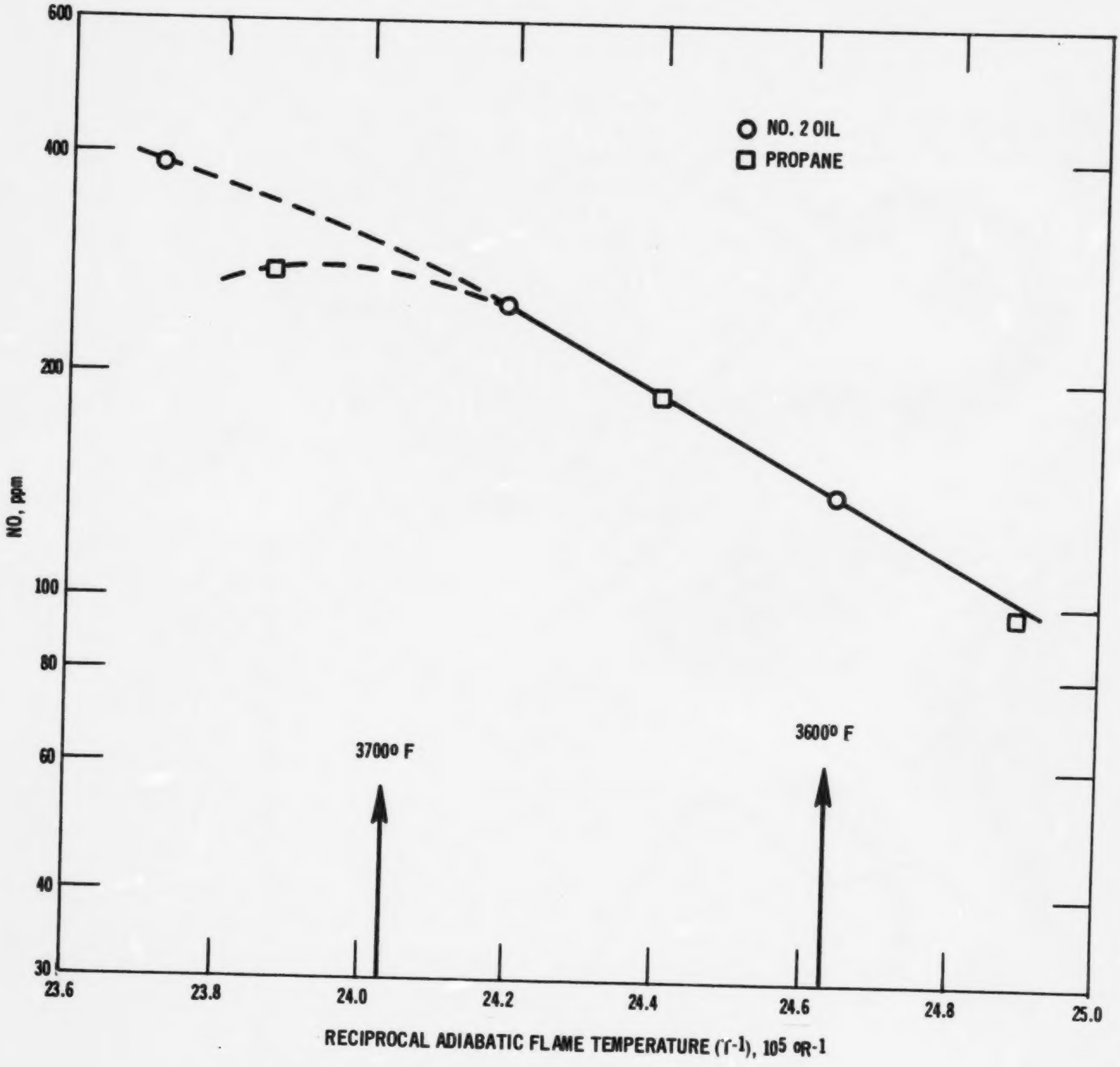

Figure 13. Peak NO emissions versus T^{-1}.

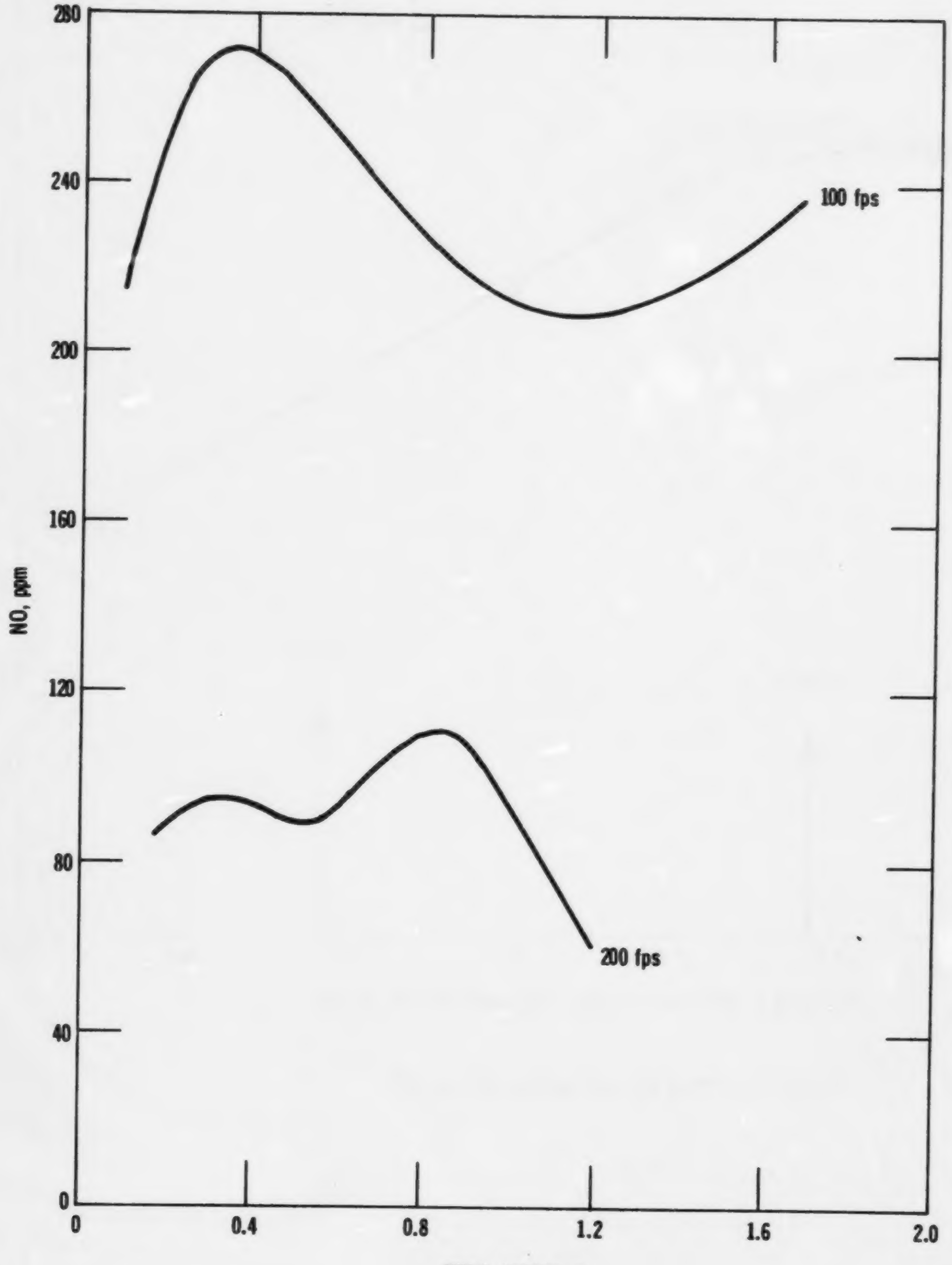

Figure 14. Effect of burner throat velocity using propane.

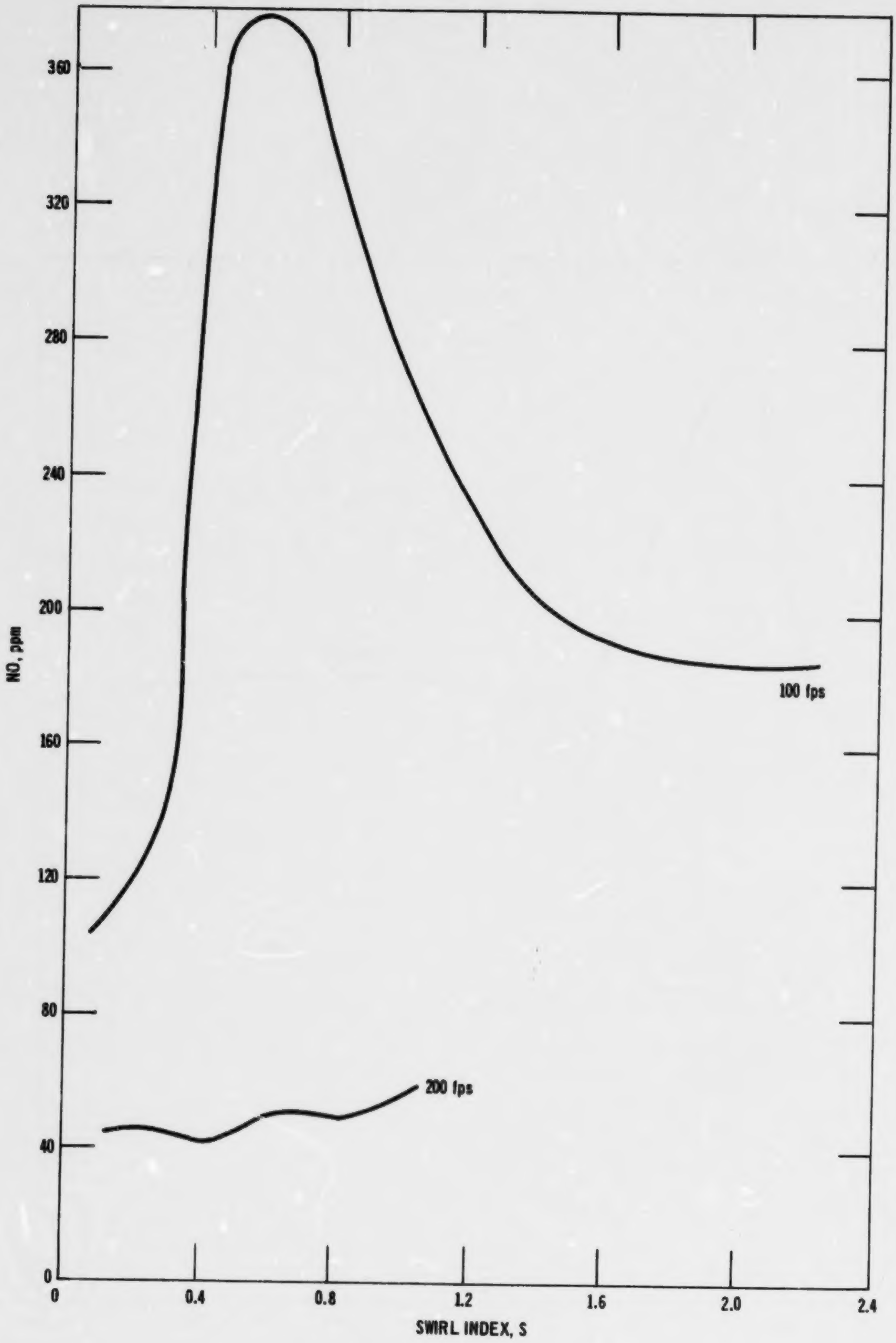

Figure 15. Effect of burner throat velocity using No. 2 oil.

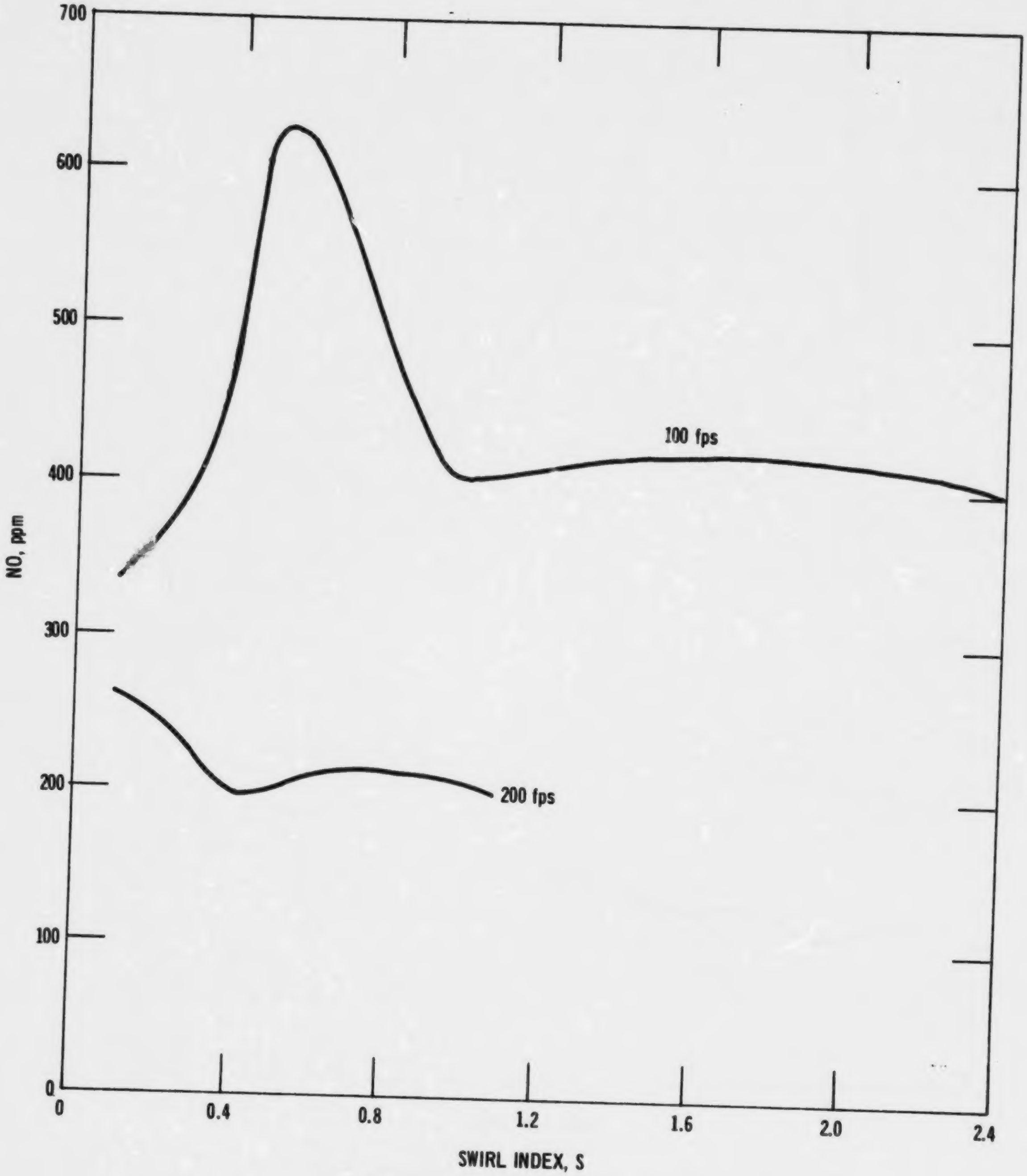

Figure 16. Effect of burner throat velocity using No. 2 oil (0.3% N).

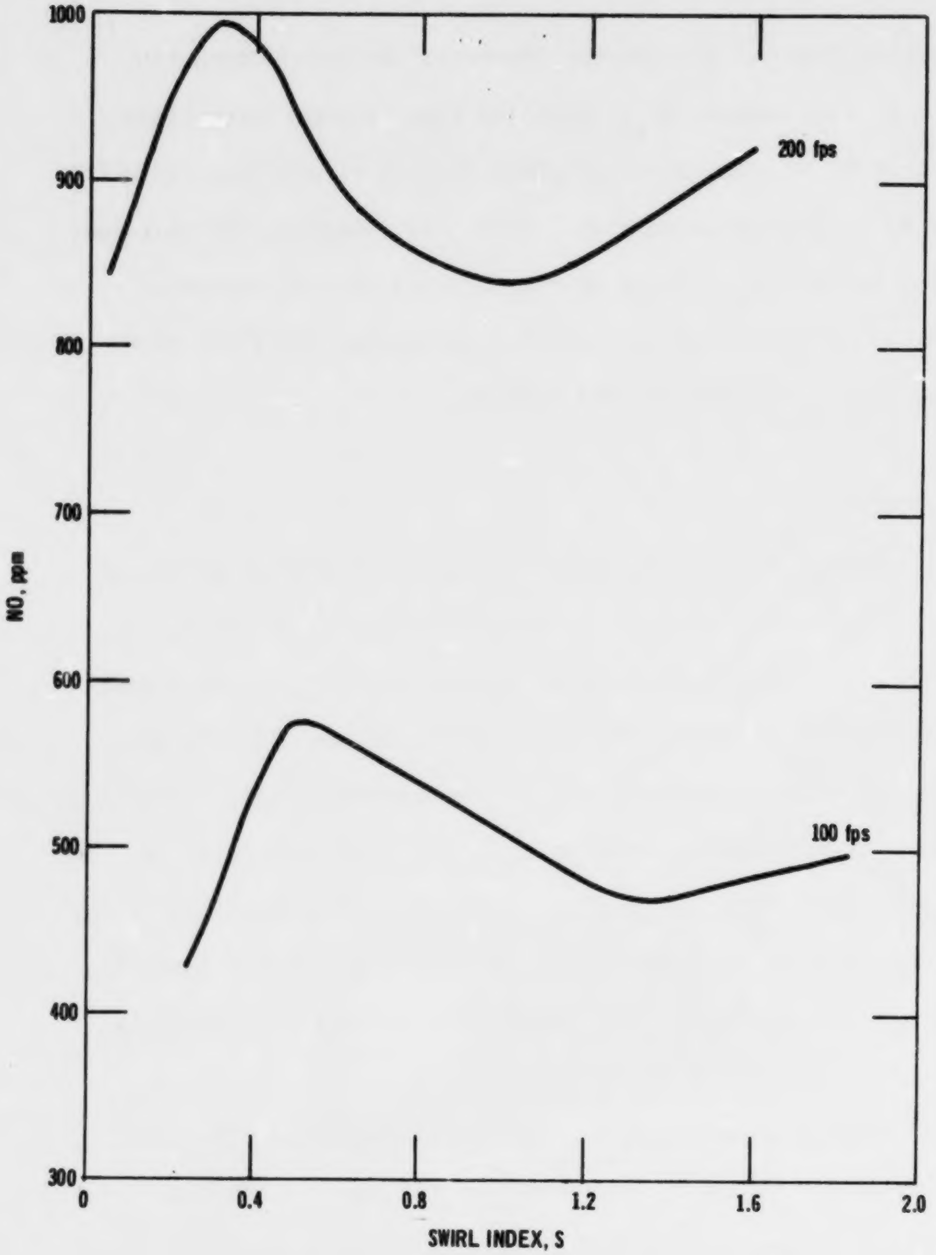

Figure 17. Effect of burner throat velocity using coal.

of "cooler" combustion products and thereby decreases the local combustion temperatures which in turn reduces NO_x. With the high nitrogen distillate the percent reduction is less but the absolute magnitude is greater, indicating a decrease in the fuel nitrogen conversion. With coal, however, the emissions actually increase with velocity. Thus, increased axial velocity appears to decrease NO_x emissions where thermal fixation dominates, but gives mixed results in systems giving both thermal and fuel NO_x.

FLUE GAS RECIRCULATION

The effect of approximately 25 percent flue gas recirculation on the NO emissions from each of the four fuels is presented in Figures 18 through 21. As the data indicate, this caused about an 80 percent reduction in emissions with propane and about a 65 percent reduction with distillate oil. In both cases the reduction was almost certainly due to reduced local flame temperature. In these cases, as with all previous work to date, the effect of swirl is essentially negligible with high FGR levels. Hence, in designing a burner for high FGR running it should be possible to set the swirl to minimize operating problems (e.g., flame instabilities), fan power, etc. without substantially affecting emissions.

As the data in Figures 20 and 21 show, FGR is not nearly as effective in reducing NO_x emissions from the 0.3 percent N distillate oil and coal flames. Again, however, there is a marked difference in the behavior of the two systems; the oil shows very little effect while the coal did experience a 38 percent reduction at 24 percent FGR. These data suggest that flue gas recirculation is going to be of limited value in systems with large quantities of fuel nitrogen (e.g., residual oils and coals).

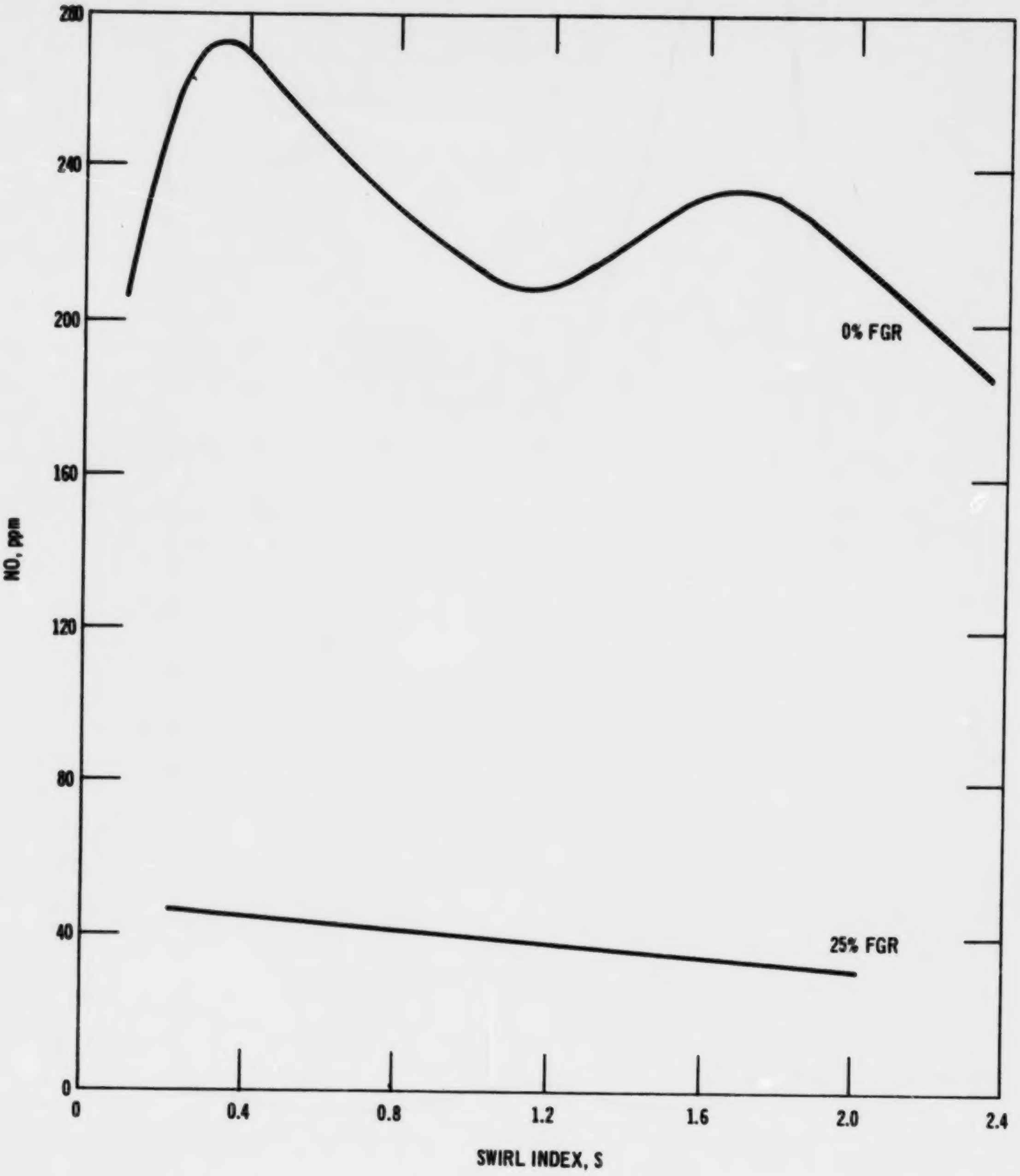

Figure 18. Effect of FGR using propane.

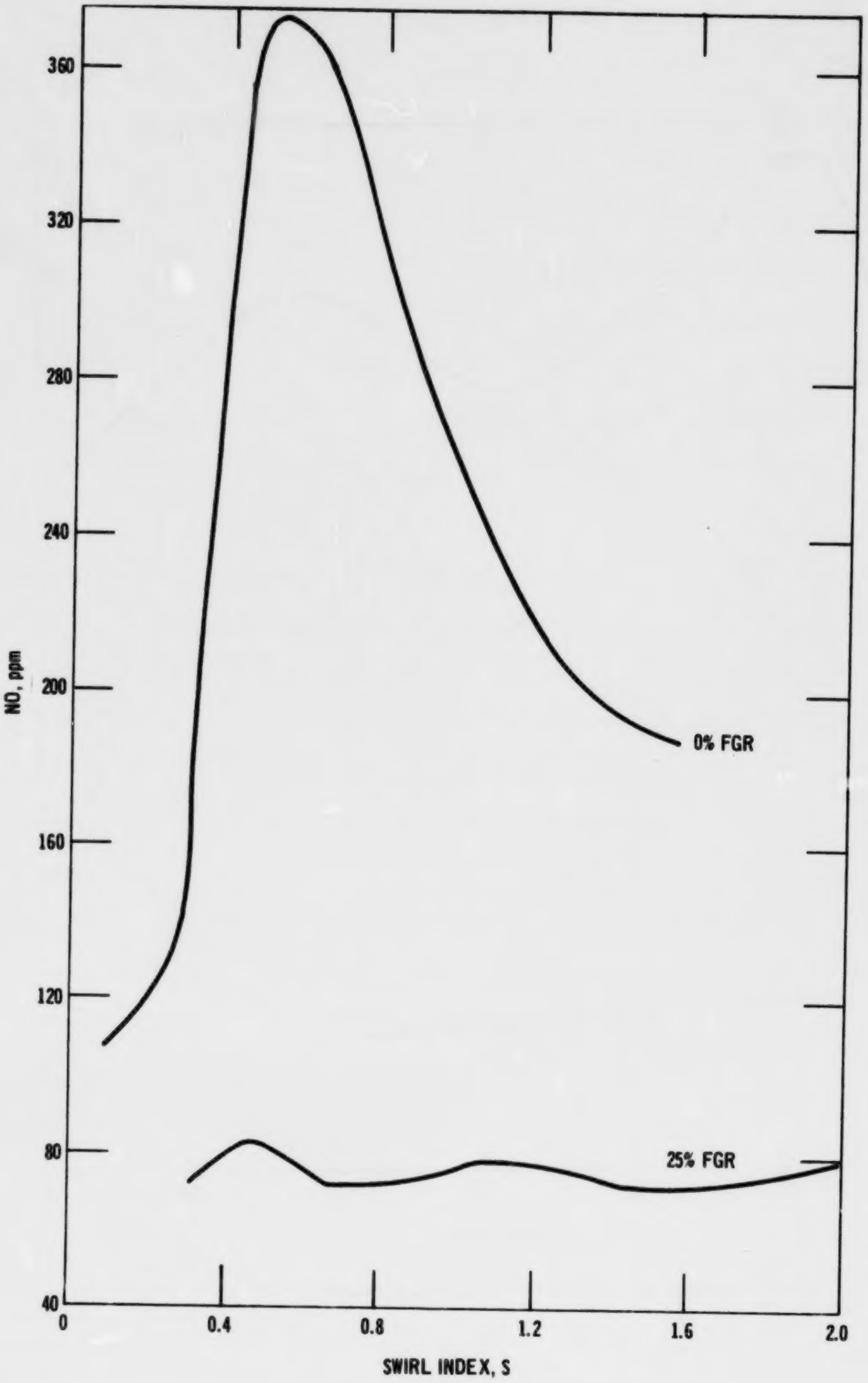

Figure 19. Effect of FGR using No. 2 oil.

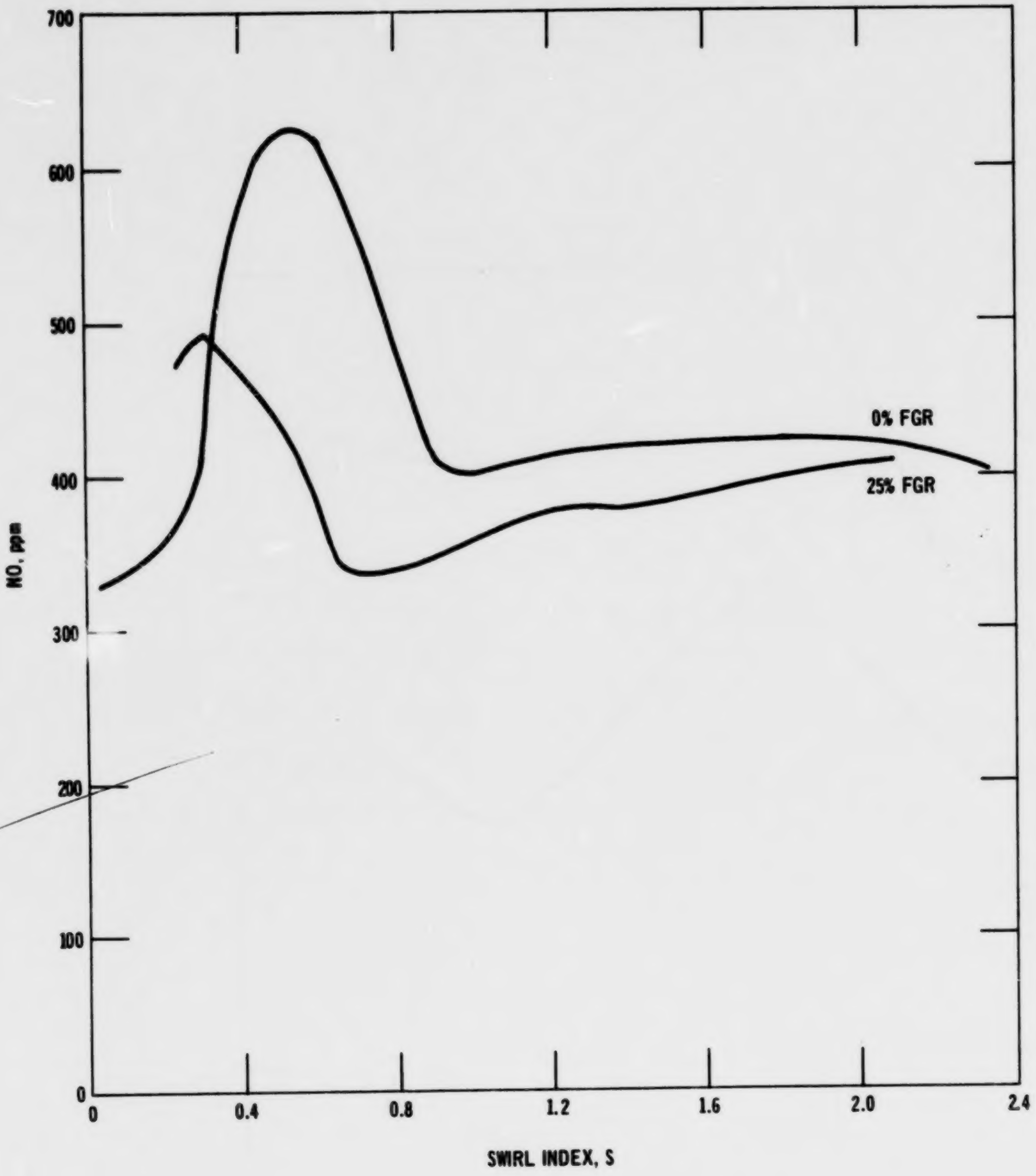

Figure 20. Effect of FGR using No. 2 oil (0.3% N).

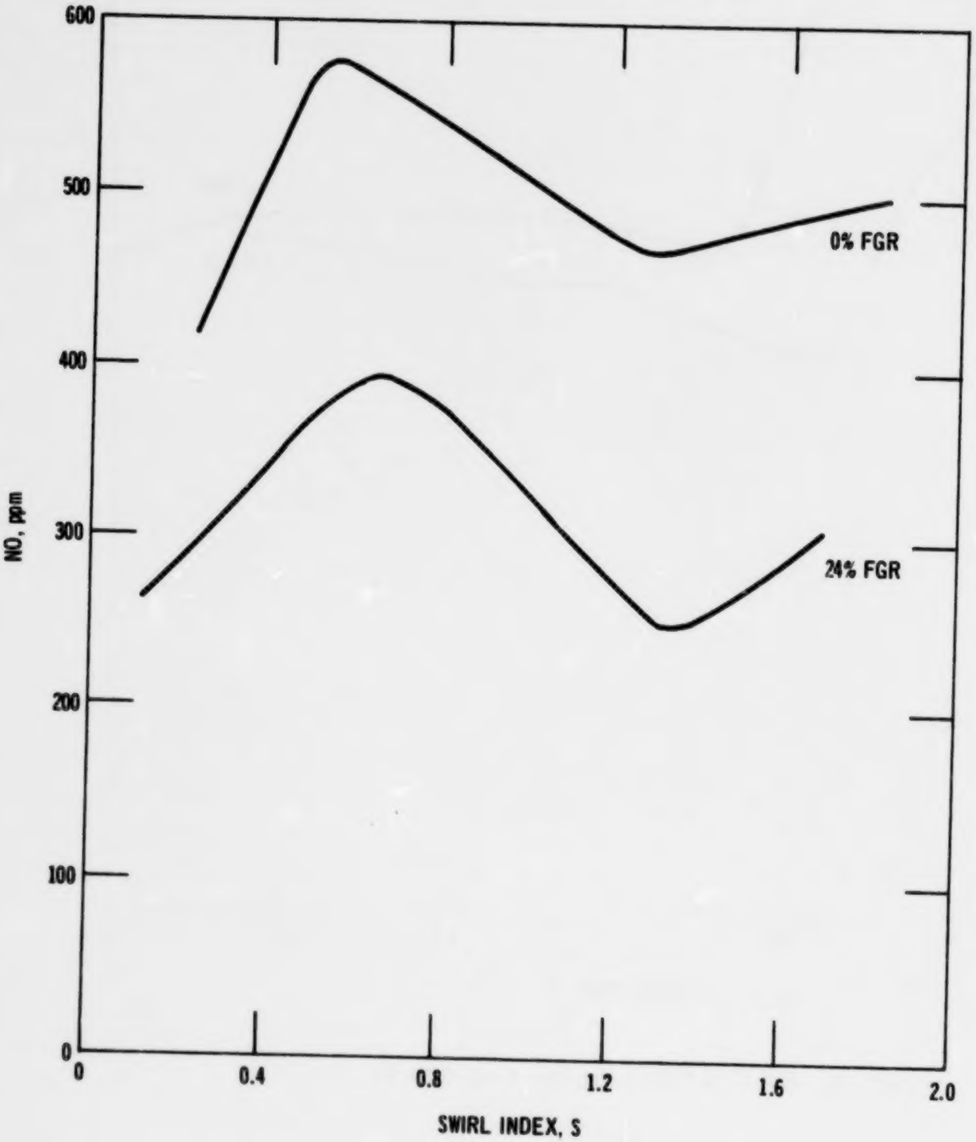

Figure 21. Effect of FGR using coal.

EFFECT OF THROAT VELOCITY ON FGR

In the previous sections we have shown that both burner throat velocity and flue gas recirculation drastically reduce thermal NO_x. In the last test series, the two were combined to investigate possible additive effects; Figures 22 through 25 show these results. As the data in Figure 22 indicate with propane, high air velocity and 25 percent FGR together reduced the uncontrolled emissions from about 240 ppm to about 30 ppm. With distillate oil, a similar level was achieved; however, the addition of FGR produced no added reduction. With the 0.3 percent N oil, the addition of FGR has no added effect over just increasing the air velocity from 100 to 200 ft/sec; with 25 percent FGR and high air velocity, the emissions are still over 200 ppm. With coal, increasing the velocity increased the NO_x as previously discussed; however, the addition of 24 percent FGR reduced the emissions to essentially the uncontrolled level.

BURNER PRESSURE DROP

Since burner pressure drop is directly related to required fan power and hence operating costs, burner ΔP must be considered in any analysis of NO_x control through burner design. The burner used in this work normally runs with a wind box pressure of 3 inches water gauge under axial conditions. At high swirl the swirl cage pressure is also about 3 inches water. (The axial would normally be less than the swirl; however, this burner has axial straightening vanes to ensure proper flow of the axial stream). Increasing the throat velocity from 100 fps to 200 fps caused a corresponding increase

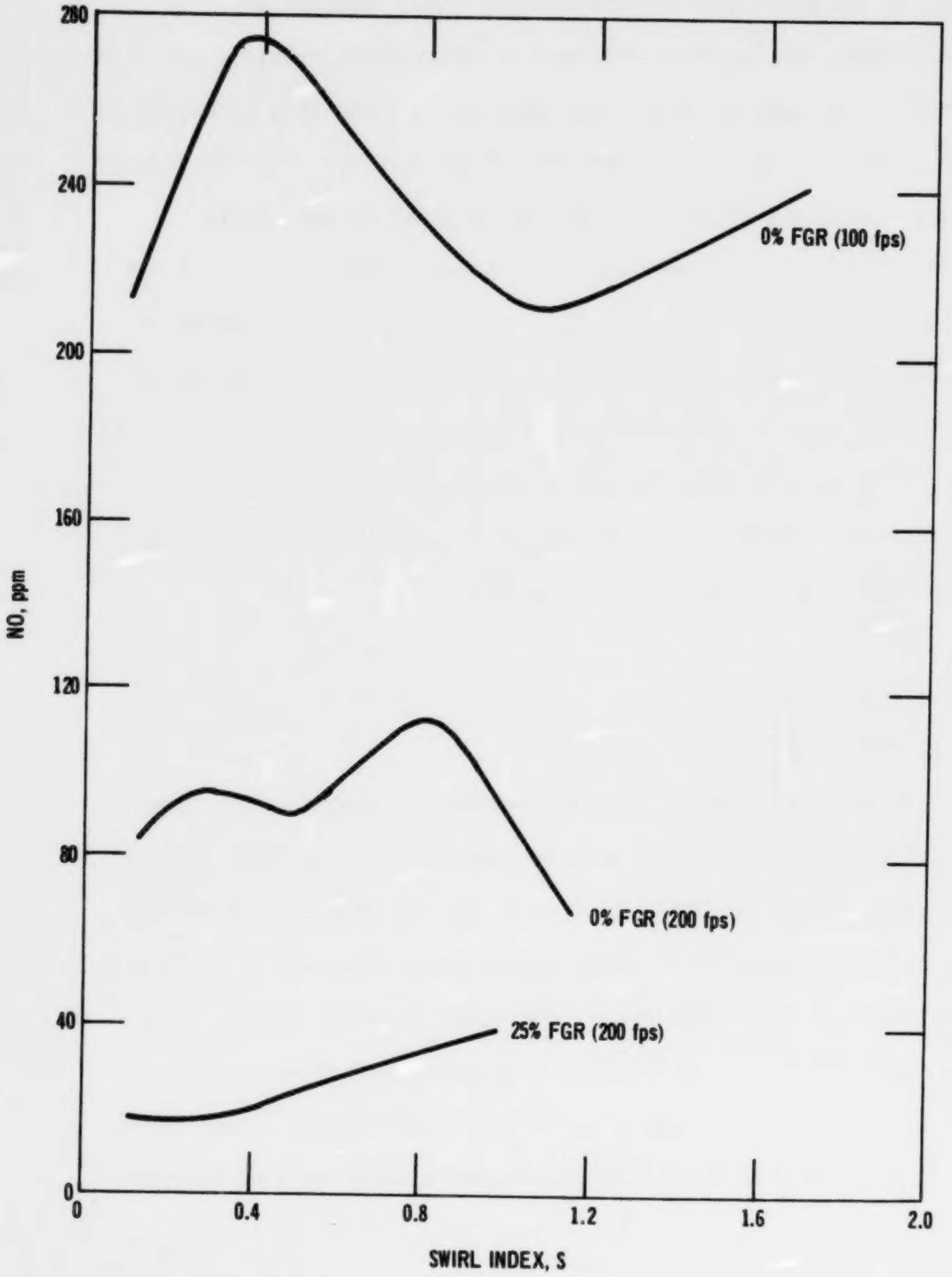

Figure 22. Effect of throat velocity on FGR using propane.

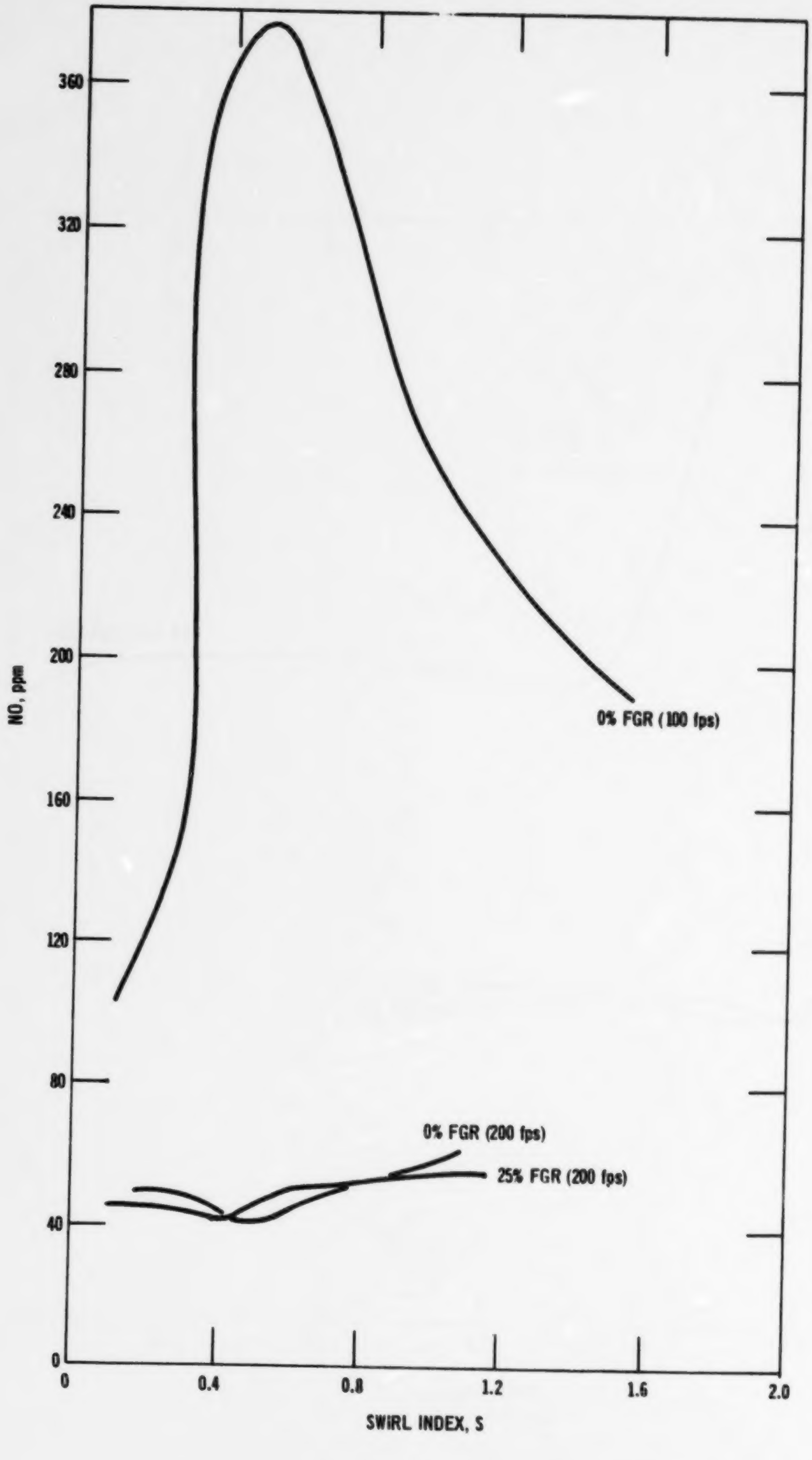

Figure 23. Effect of throat velocity on FGR using distillate oil.

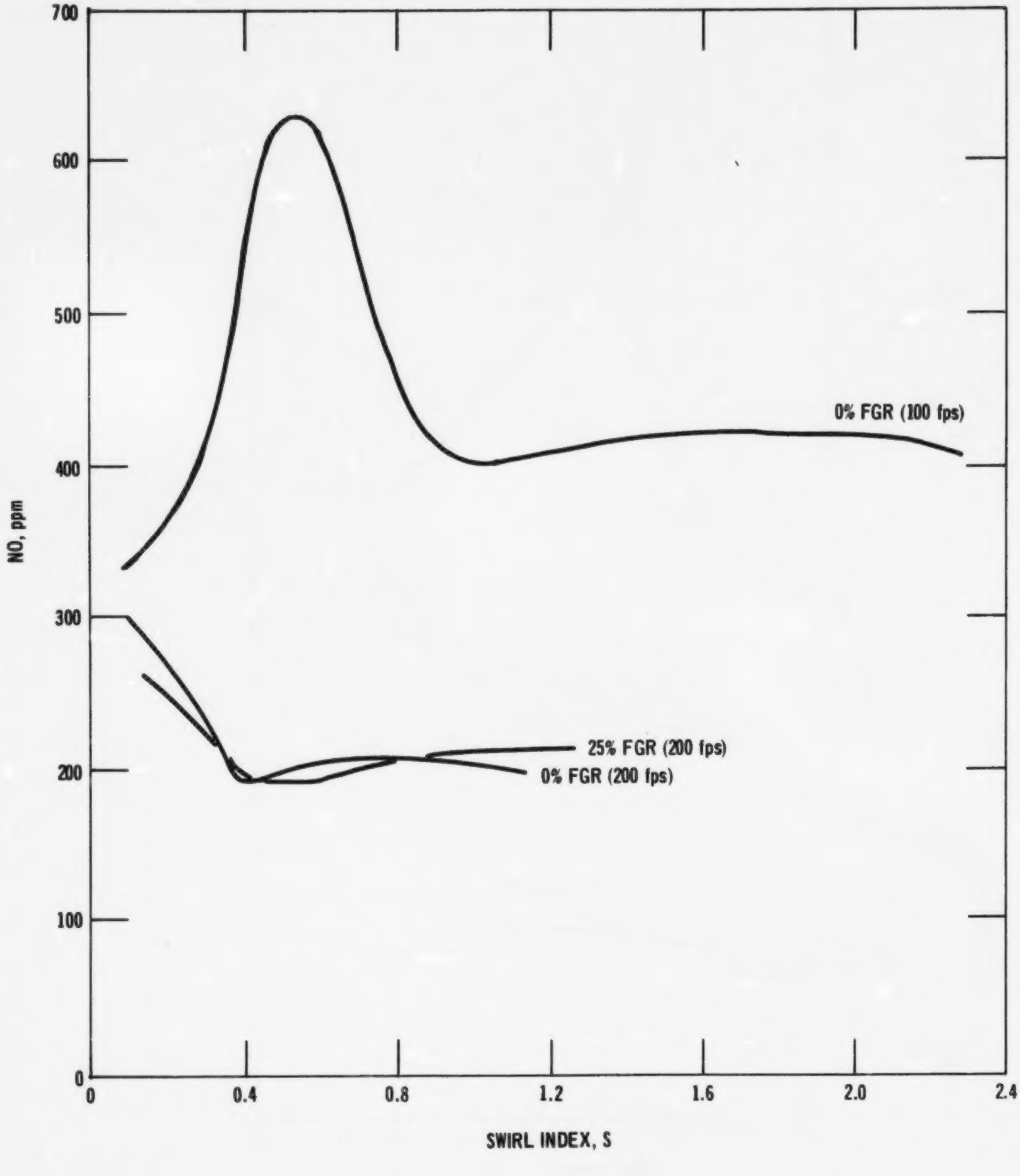

Figure 24. Effect of throat velocity on FGR using No. 2 oil (0.3% N).

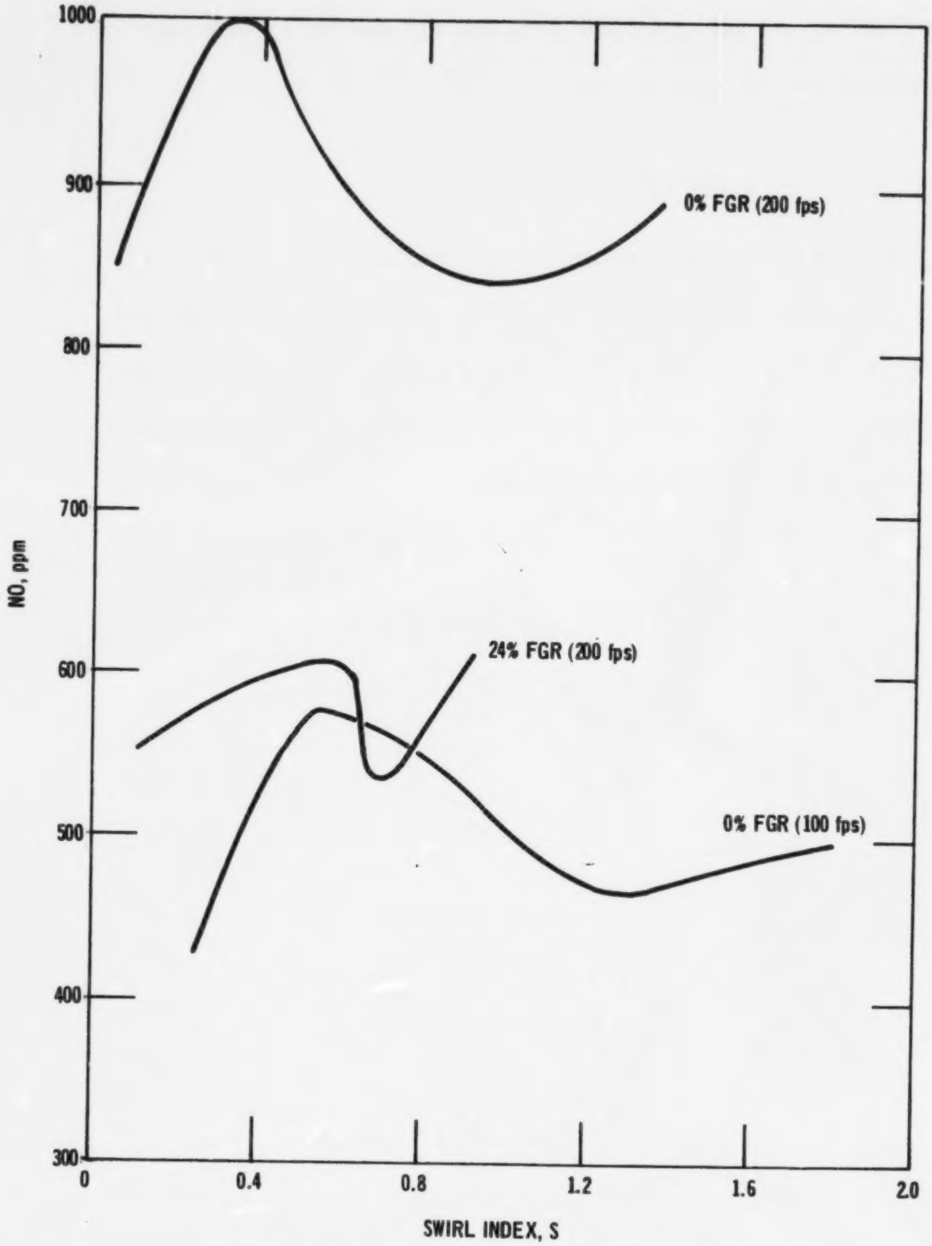

Figure 25. Effect of throat velocity on FGR using coal.

in both the axial and swirl streams to 5 inches water gauge. FGR had no noticeable effect on burner pressure drop but of course it did require additional fan power and ducting.

OTHER EMISSIONS

CO and HC emissions were continuously measured during all tests and were essentially zero with propane and distillate. With pulverized coal combustion, HC emissions were always less than 10 ppm. Spot checks for NO_2 were also made. The data confirm that the primary NO_x emission is NO; in all cases examined, NO_2 was less than 5 ppm.

CONCLUSIONS

RESULTS

1. Under as nearly identical conditions as possible average NO_x emissions are as follows: propane $\approx$ distillate oil $<$ 0.3% N oil $<$ coal.

2. Increasing air preheat substantially increases the emissions from propane and distillate oil and causes a lesser increase with the high nitrogen distillate and pulverized coal.

3. Under peak NO_x conditions propane and distillate oil are essentially identical with respect to NO_x emissions. There is little evidence that the difference in the phase of the fuel (gas vs. liquid) has any significant effect on emissions.

4. Increasing burner throat velocities substantially reduces emissions with propane and distillate oil, has little effect with the 0.3 percent N oil, and increases emissions with coal.

5. Flue gas recirculation is very effective with propane and distillate oil, has almost no effect with the 0.3 percent N oil, and is only moderately effective with pulverized coal. When effective FGR is essentially independent of burner swirl.

6. Doped distillate oil (0.3 percent N) and coal behave very differently even though at least half the NO_x emissions from both are almost certainly the result of fuel nitrogen conversion.

IMPLICATIONS

1. Conversion of a unit from a low nitrogen oil to gas or vice versa

should not result in major increases (or decreases) in NO_x emissions.

2. Increasing combustion air preheat can be expected to increase thermal NO_x unless some type of counteracting measures are taken (e.g., FGR).

3. Increasing burner throat velocities (and hence entrainment of cooled combustion gases) can be as effective a control technique for thermal NO_x as application of substantial FGR.

4. Flue gas recirculation cannot be expected to provide large emission reductions with high nitrogen oils or coals.

NOTE

The implications cited above (1 through 4) are based on the results of this research investigations.

FUTURE EFFORTS

The experimental work on this program during the next few months will be directed at finishing the test matrix and at specialized analysis experiments. The present coal data will be extended to include a wider variety of injector types at higher excess airs. Natural gas and No. 6 oil will be examined. Two stage combustion testing will also be conducted with each of the fuels.

In one of the limited, specialized test series coal, No. 6 oil, and the 0.3 percent N distillate will be burned in an Ar/O_2 atmosphere. Finally, some of the anomalies which have surfaced so far will be examined in greater detail. For example, increasing the burner throat velocity has been proposed as a means of achieving flue gas recirculation inside the furnace (through the entrainment cooled product gases). Further, with gas and distillate oil increased throat velocity and FGR do indeed cause similar, significant NO_x reductions. However, with the 0.3 percent N oil doubling the velocity halves the NO_x while 25 percent FGR does nothing. With coal, doubling the velocity more than doubles the NO_x while 24 percent FGR reduces it by 40 percent.

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BURNER DESIGN PRINCIPLES FOR MINIMUM NO_x EMISSIONS

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1. INTRODUCTION

Various control techniques are available to reduce nitrogen oxide (NO_x) emissions from large steam raising plant. These techniques include:-

- operating modifications ie. reduced load, excess air or preheat;
- combustion modifications i.e. flue gas recirculation or staged combustion;
- burner modifications.

All these techniques will necessitate variations in accepted plant operating conditions and may also increase the unit cost of the power produced. This paper discusses the principles upon which burners with minimum emission characteristics can be designed. The paper is mainly concerned with pulverised coal (p.f.) burners for utility boilers, however reference will be made to other fuels. In the long term burner modifications may well provide the most efficient method of controlling NO_x emissions from all forms of fossil fuel fired furnaces and boilers.

Minimum NO_x emission characteristics are not the only desirable design feature of burners. Consideration must also be given to:

- ignition stability;
- fuel burnout;
- noise production;
- the generation of other pollutants;
- burner production and running costs;
- peak temperatures;
- flame shape.

The design principles for minimum NO_x emissions will have an effect upon many of the characteristics listed above and wherever possible these effects will be discussed in the present paper.

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2. NO_x FORMATION IN TURBULENT DIFFUSION FLAMES

The NO_x emitted from fossil fuel fired combustors is the result of two processes:-

- the oxidation of molecular nitrogen producing thermal NO_x;
- the conversion of nitrogen compounds contained in the fuel, fuel NO_x;

In order to understand the influence of various burner parameters on the formation of NO_x in flames it is necessary to briefly summarise the controlling influences on the formation of thermal and fuel NO_x.

2.1. The Formation of Thermal NO_x

The formation of thermal NO_x in combustion processes has been studied extensively in recent years. Although the precise details of the interaction between hydrocarbon combustion and thermal NO_x formation remain unknown, the controlling influences of time, temperature and combustion stoichiometry are generally recognised [1, 2]. Virtually all attempts to control the formation thermal NO_x involve the reduction of peak temperatures.

In the majority of combustors thermal NO_x formation can be considered as a flame phenomenon since residence times at bulk gas temperatures are normally too short to allow the formation of significant quantities of NO_x within the bulk gases. The amount of NO_x produced within the flame region depends upon:-

- the initial temperature of the freshly formed combustion products within the flame;
- the rate of temperature decay of these freshly formed products.

Both the initial temperature and the rate of temperature decay can be controlled by burner parameters since these parameters dictate the mixing pattern of the fuel, air and recirculating gases.

The temperature of the freshly formed products of combustion within the flame will obviously depend upon the composition and enthalpy of the reactants. Combustion in diffusion flames is complicated because the reactants must be mixed on a molecular scale before combustion can take place. The location and mixture strength of the reaction zone in diffusion flames are matters for conjectures; reaction will proceed wherever the mixture strength lies within the limits of flammability and there is a source of ignition. Thus maximum temperatures are attained when the fuel reacts in proportions close to stoichiometric before either the fuel or [illegible]r have been diluted with recirculating products. The high temperature combustion products are cooled subsequent to formation by mixing with the bulk gases and their rate of temperature decay depends upon the rate of mixing with and temperature of the bulk gases.

2.2. The Formation of Fuel NO_x

Both residual fuel oils and coal contain nitrogen compounds. Although it is almost universally accepted that the oxidation of these nitrogen compounds contributes significantly to the total NO_x emission from combustion processes,very little is known concerning the oxidation process. The oxidation of the fuel nitrogen compounds in flames can be considered in two stages:-

- the evolution of nitrogen compounds XN from liquid droplets or coal particles;
- subsequent reactions of these nitrogen compounds.

No positive identification of the intermediate nitrogen compounds XN has been made under flame conditions. However it is probable that both the type of compound evolved and the rate of the evolution will depend upon the heating rate of the fuel. At the present time theories concerning fuel NO_x formation must be based upon information gained from experiments with doped fuels or from the combustion of simple nitrogen compounds.

Sternling and Wendt [3] have recently summarised the available information concerning the ultimate fate of fuel nitrogen compounds in combustion processes:-

- with doped fuel oils it has been shown that the fraction of fuel nitrogen converted to nitric oxide increases with increasing excess air and decreases with fuel nitrogen concentration [4,5];

- it is possible to reduce NO to N_2 under fuel rich conditions;
- the conversion of fuel nitrogen appears to be a strong function of burner/combustion chamber combination;
- flue gas recirculation does not appear to be effective in reducing emissions of fuel NO_x [5].

In order to explain the above experimental information it is necessary to postulate some kind of kinetic mechanism. Fenimore [6] suggests that all the fuel nitrogen goes through an intermediate compound I which reacts either to produce NO or N_2:-

$$I + R \longrightarrow NO + \ldots\ldots\ldots\ldots \qquad \underline{1}$$

$$I + NO \longrightarrow N_2 + \ldots\ldots\ldots\ldots \qquad \underline{2}$$

Fenimore considers that R is probably CH and that I could either be NH_2 or N. In an attempt to model the reduction of NO under fuel rich conditions Sternling and Wendt [3] account for the formation of the nitrogen-nitrogen bond by the reaction:-

$$N + NO \longrightarrow N_2 + O \qquad \underline{3}$$

which is faster under fuel rich conditions than:-

$$N + O_2 \longrightarrow NO + O \qquad \underline{4}$$

2.3 NO_x Formation in Pulverised Coal Flames

The combustion of p.f. is a complex process involving:-

- particle heating by convection and radiation;
- rapid evolution of the volatile fraction;
- combustion of the volatile fraction;
- char burnout.

The fuel is normally injected into the furnace as a coal/air suspension. The proportion of air in the primary jet varies but is typically between 15 and 20% of the total air flow. The additional air required for combustion is supplied in an annular preheated secondary stream surrounding the primary jet. Upon injection into the furnace the particles receive heat either by radiation from the surroundings (which may include furnace walls, bulk gases and the ignition front) or by convection from the preheated secondary stream and entrained recirculating gases. When the coal particles reach a sufficiently high temperature they begin to decompose producing tars and gases usually referred to as volatiles. The composition of the volatiles and the particle weight loss depends upon the time/temperature history of the particle. Thus the rate of heating of the particle and its final temperature influence the quantity and composition of the evolved volatiles.

The volatile fractions begin to combust when the temperature is sufficiently high and the fuel/air mixture lies within the flammable limits. The time required for the ignition of the volatile fractions depends upon the rate of mixing of the primary/secondary and recirculation gases and the bulk gas temperature. The distance from the point of injection and the visible ignition front will be referred to as the ignition distance. The solid particles remaining after devolatilisation, soot, cenospheres and cellular particles are collectively referred to as char. There is a fundamental difference between the combustion of the char and volatile fractions. The reactions involved in the combustion of the volatiles have finite rates but these are usually high compared with the surface reactions involved in the combustion of char. Also the combustion of the char particles involves several steps in sequence:-

- transport of oxygen or other reactant gas to the particle surface;
- reaction with the surface;
- transport of the reactants away from the surface.

The overall reaction rate is, of course, dependent upon the slowest of these steps.

NO_x formation in p.f. flames may be considered in four stages:-

- fuel NO_x formation during volatile combustion;
- thermal NO_x formation during volatile combustion;
- fuel NO_x formation during char burnout;
- thermal NO_x formation during char burnout.

In the absence of definite information it is necessary to make several simplifying assumptions concerning NO_x formation in p.f. flames in order to explain the effect of burner parameters on total emissions. These assumptions are:-

- the most significant fraction of the total emission is fuel NO_x. Thermal NO_x will be produced during the combustion of the volatile fractions but peak temperatures will be low since the volatiles will be diluted with entrained combustion products prior to ignition. During char burnout high surface temperatures could produce thermal NO_x but this possibility is ignored.

- the majority of the fuel NO_x is produced during the combustion of the volatile fraction. Sternling and Wendt [3] consider that the total nitrogen content of the initial coal will be divided between the char and volatile fractions and therefore char combustion could be a source of fuel NO_x. However, measurements tend to suggest that this will be a negligible fraction of the total emission.

Accepting these assumptions, then the conversion of volatile nitrogen compounds to NO or N_2 is explained by the following sequence of events:-

a) the coal particles are heated and the volatile fractions evolved containing nitrogen compounds XN, which may react directly or undergo pyrolysis prior to reaction in combustion zones;

b) in the combustion zone two overall competing reactions can take place:

$$XN + Y \longrightarrow NO + \ldots\ldots\ldots\ldots \qquad \underline{5}$$

$$XN + Z \longrightarrow N_2 + \ldots\ldots\ldots\ldots \qquad \underline{6}$$

The identity of reactants Y and Z needs to be specified. The ultimate conversion of XN to either N_2 or NO is dependent upon the quantity of oxygen associated with the combusting volatiles. In oxygen rich regions reaction 5 will predominate and the formation of fuel NO_x is promoted. In oxygen deficient regions reaction 6 is dominant and the conversion of fuel nitrogen to NO is limited. Burner parameters can be used to vary the emission of NO_x from p.f. flames because they control the mixing history of the fuel particles, the combustion air and the recirculating gases which will dictate the oxygen available during the combustion of the volatile fractions.

3. BURNER DESIGN PARAMETERS FOR THE CONTROL OF NO_x EMISSIONS FROM FOSSIL FUEL FLAMES

Investigations at IJmuiden have shown that NO_x emissions from natural gas, fuel oil and p.f. flames can be varied over a wide range by a suitable choice of burner parameters. The parameters which have been investigated include:-

- the method of fuel injection;
- the position of the fuel injector;
- the degree of swirl in the combustion air;
- the velocity of the combustion air;
- the angle of the burner exit;
- the presence of swirl impellers on the oil gun;
- the division of the total air between primary/secondary and tertiary streams;
- the velocity of the tertiary stream.

The investigations were carried out in an almost uncooled refractory tunnel furnace (2 m x 2m x 6.25 m) and relate to single burner emissions. The burner used during the investigations (see fig. 1) had the facility to vary the swirl intensity of the secondary stream continuously from zero to a maximum value determined by the burner geometry.

In the results presented in this paper the swirl intensity of the secondary stream will be expressed as a relative swirl index, R_s, defined by:

$$R_s = \frac{\text{Actual opening of the swirl blocks}}{\text{Maximum opening of the swirl blocks}}$$

Figure 2 shows the relationship between R_s and S, the swirl number for several combinations of burner throat diameter and outside diameter of the primary pipe. Swirl number is a dimensionless criterion that has been used to characterise swirling flows and is defined by:

$$S = \frac{\text{flux of angular momentum}}{\text{flux of axial momentum x burner radius}}$$

The two parameters with the most influence on NO_x emissions are the method of fuel injection and the swirl intensity of the combustion air. Figures 3, 4 and 5 illustrate how flue gas nitric oxide concentrations depend upon these parameters for natural gas, fuel oil and pulverised coal flames. The combination of these parameters also controls such important characteristics as flame stability, smoke production and heat release rate. The influence of the method of fuel injection and the swirl intensity of flame characteristics can be more easily understood by reference to the flame classification scheme presented in fig. 6. This scheme refers to gaseous, liquid and solid flames.

a) Lifted Flames (fig. 6a)

The ignition front is stable some distance downstream from the primary injector. The stabilisation of lifted natural gas flames is helped by high external recirculation temperatures. An increase in throughput can blow-off the lifted flame completely.

b) Injector Stabilised Flames (fig. 6b)

This type of flame is normally produced by single hole injectors. Stability is achieved either by a "bluff body effect" or by an auxiliary pilot. Although the fuel jet is entirely surrounded by flame, the flame does not completely fill the burner exit.

c) Primary Jet Penetrating a Region of Reverse Flow (fig. 6c)

With single hole injectors of high primary velocity and "medium" swirl or low primary velocities and low swirl it is possible that the primary jet will penetrate the swirl induced internal reverse flow zone. The internal reverse flow zone then takes the form of an annulus surrounding the central fuel jet. The flame may be divided into two sections, a short bulbous zone close to the burner and a long tail. The two sections are connected by a neck which under particular circumstances may break and only the bulbous base remains.

d) Divided Fuel Jets (fig. 6d)

This type of flame with a closed internal recirculation zone on the flame axis is characteristic of the type of flame used in utility boilers. It is short with a high heat release rate per unit volume of "flame". It can be produced in p.f. flames with intermediate swirl values by using radial injectors, coal spreaders, annular injectors or low velocity single hole injectors. This type of flame is produced with fuel oil by the use of pressure jets or steam atomised injectors.

Although the flames of different fuels can be classified according to the simple scheme shown in Fig. 6, their emission characteristics are dependent upon the fuel type. Thus although p.f. flames with divided fuel jets always give maximum emissions, the emission levels of all four types of natural gas flame are similar under particular conditions.

In section 2 the conditions necessary to reduce the formation of both thermal and fuel NO_x were discussed. Ample experimental evidence has been obtained to show that burner parameters affect NO_x emissions from natural gas, fuel oil and p.f. flames. Emissions from p.f. flames can be reduced to the same level as those of natural gas and fuel oil flames with comparable input conditions (i.e. preheat and thermal load). However, to achieve this emission level radically different flame characteristics must be tolerated. Consequently design parameters for minimum NO_x emissions can be judged from two viewpoints:-

- what are the burner parameters necessary to give minimum emissions regardless of flame characteristics?
- which parameters can be used to reduce emissions without seriously affecting flame characteristics?

Flame characteristics are not the only consideration, the design parameters necessary to reduce NO_x may also increase the burner pressure drop or increase burner maintenance costs.

If the assumptions suggested in section 2 are correct then the minimum NO_x emissions are achieved by restricting the available oxygen during the combustion of the volatile fractions. Ideally the volatile fractions containing the nitrogen compounds XN should burn in a diffusion flame because this would give the minimum conversion to NO [3]. However this is not possible since the coal is supplied with air and the volatiles are mixed with air as they are evolved from the coal particles. Also mixing of the primary and secondary streams prior to ignition will increase the oxygen-coal ratio from the input condition.

The emission curve presented in fig. 7 illustrates the reduced emission resulting from restricting the amount of primary/secondary mixing. These results were obtained accidentally. Initially the fuel injector was uncooled and at high swirl levels with the ignition front stable on the injector a coating of red hot char was deposited on the thick interface. This char acted as an ignition source so that when the swirl was reduced to zero the ignition zone remained stable on the injector. Fig. 7 shows measured flue gas NO concentrations as the swirl level is increased to a maximum and then decreased. The coal jet was always enclosed by a visible ignition zone as the swirl was reduced to zero.

The only significant difference between the emission levels is at low swirl levels. This difference is attributed to the variation in the coal-oxygen ratio during the combustion of the volatile fractions for the lifted flame and the injector stabilised flame. Prior to injection the coal oxygen ratio of the two flames is identical. However the lifted flame has an ignition distance of approximately 0.75 m and mixing between the primary and secondary stream increases the amount of oxygen associated with the volatile fractions. With the injector stabilised flame the oxygen available for mixing with the evolved volatile fractions is limited to that of the input primary stream since the primary and secondary streams are separated by a region of combusting volatiles. Provided sufficient combustible gases are available and the ignition front is complete, oxygen from the secondary stream will not be able to penetrate into the fuel jet.

Thus the conditions necessary for minimum NO_x emissions from p.f. flames are:-

- minimum primary air supply;
- minimum primary/secondary mixing prior to completion of the combustion of the volatile fraction;
- ignition stability at the injector;
- dilution of the secondary air with recirculating combustion products prior to contact with the fuel.

These conditions are satisfied by using a single hole high velocity injector positioned at the exit of the burner divergent. The coal is supplied with the minimum amount of primary air and swirl is used to stabilise the ignition at the injector. The consequence of variation from these conditions can be seen from the following examples:-

- Fig. 8 shows the effect of primary velocity; the higher the primary velocity, the lower the emission level. The variations in emission level are caused by variation in mixing pattern produced by the interaction of the internal reverse flow regions and the primary jet. Lifted flames were observed with all injectors for swirl levels less than $R_s = 0.4$. With the low primary velocity of injectors B and C the swirl induced reverse flow zone is sufficient to split the fuel jet as it emerges from the injector producing the flame type shown in fig. 6c. Thus primary/secondary mixing is enhanced and emissions increase. As the swirl level is increased, combustion within the burner divergent intensifies causing an increase in axial momentum which enables the primary jet to penetrate the internal reverse flow region. The primary/secondary mixing is reduced and consequently the emission decreases. Injector B, which has the lowest primary momentum, produces a flame with a divided fuel jet which then changes to a flame where the internal reverse flow zone is penetrated by the fuel jet and then reverts to a divided fuel jet flame as the swirl is increased;

- The effect of increasing the primary air supply whilst maintaining the primary velocity can be seen in fig. 9. Minimum emissions are obtained with the lowest primary air percentage;

- Figs.10a and 10b show that emissions are less when the injector is placed at the exit of the divergent and emissions are less with a divergent angle of 25° rather than a parallel exit.

Earlier it was stated that flames with divided fuel jets are normally used in utility boilers. It is possible to produce this type of flame without swirling the combustion air by injecting the p.f. normal to the burner axis. Provided some swirl is used divided fuel jet flames can also be produced with an annular or a low velocity single hole injector or some other device to spread the fuel. Due to the rapid mixing divided fuel jet flames have high heat release rates and wide ignition stability limits. However, this flame type has the maximum NO_x emission characteristics with p.f. It is believed that this is because the coal particles are intimately mixed with all the available air, thus providing ideal conditions for fuel NO_x formation.

The results presented in figs. 11 and 12 show that with radial or annular injection varying swirl or primary air percentage has very little influence on the emission level. Using a coal "spreading injector" three possibilities exist to vary emission levels:-

- vary the swirl level of the secondary air. In fig. 13 it can be seen that NO_x emissions increase as the swirl intensity of the secondary air increases. This type of injector would not normally be used at swirl levels less than $R_s = 4$ since ignition is not stable within the burner exit. At high swirl intensities the emission is reduced after the flame form passes through an instability condition. The difference between the high and low emission conditions is visually apparent: at high swirls the flame forms a closed ball;

- increase the primary air flow. Emissions are reduced because the increased axial momentum reduces the effectiveness of the spreading device and thus less fuel/air mixing takes place (see fig. 14a).

- change the position of the point of fuel injection. In fig. 14b it can be seen that emissions are reduced when the point of injection is changed. Emissions are less when the injector is moved towards the exit plane of the burner.

Although emissions from divided fuel jet p.f. flames can be reduced by burner parameters, the reductions are bought at the expense of increased burner pressure drop (to produce swirl) or by a lengthening of the flame. Recent work at IJmuiden has shown that triple concentric burner systems have the potential to reduce emissions from flames with divided fuel jets with gaseous liquid and solid fuels. However, the tertiary velocity is critical and incomplete combustion may result from inadequate burner design.

4. CONCLUSIONS

1.
NO_x emissions from fossil fuel fired furnaces and combustors can be reduced by the optimisation of burner design parameters.

2.
NO_x emissions from p.f. flames can be reduced to the same level as those from comparable gas flames. However, the reduced emission is achieved by a radical change in flame form. Adequate ignition stability and burnout are possible but the flame becomes longer and thinner.

3.
Limited reductions are possible with flame forms which are in use at present.

4.
Burners with tertiary air supplies can be designed to reduce NO_x emissions without changing the flame form. However, care must be exercised in design, otherwise CO and solid emissions can be increased.

5. ACKNOWLEDGEMENTS

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APPENDIX I.

FUEL COMPOSITIONS

Natural Gas

CH_4	81,3 %
C_2H_6	2,9 %
C_3H_8	0,4 %
C_4H_{10}	0,4 %
C_nH_m	0,1 %
CO_2	0,8 %
N_2	14,4 %

Fuel Oil

C	86,05%
H_2	11,54%
N_2	0,24%
S	0,57%
Ash	0,01%

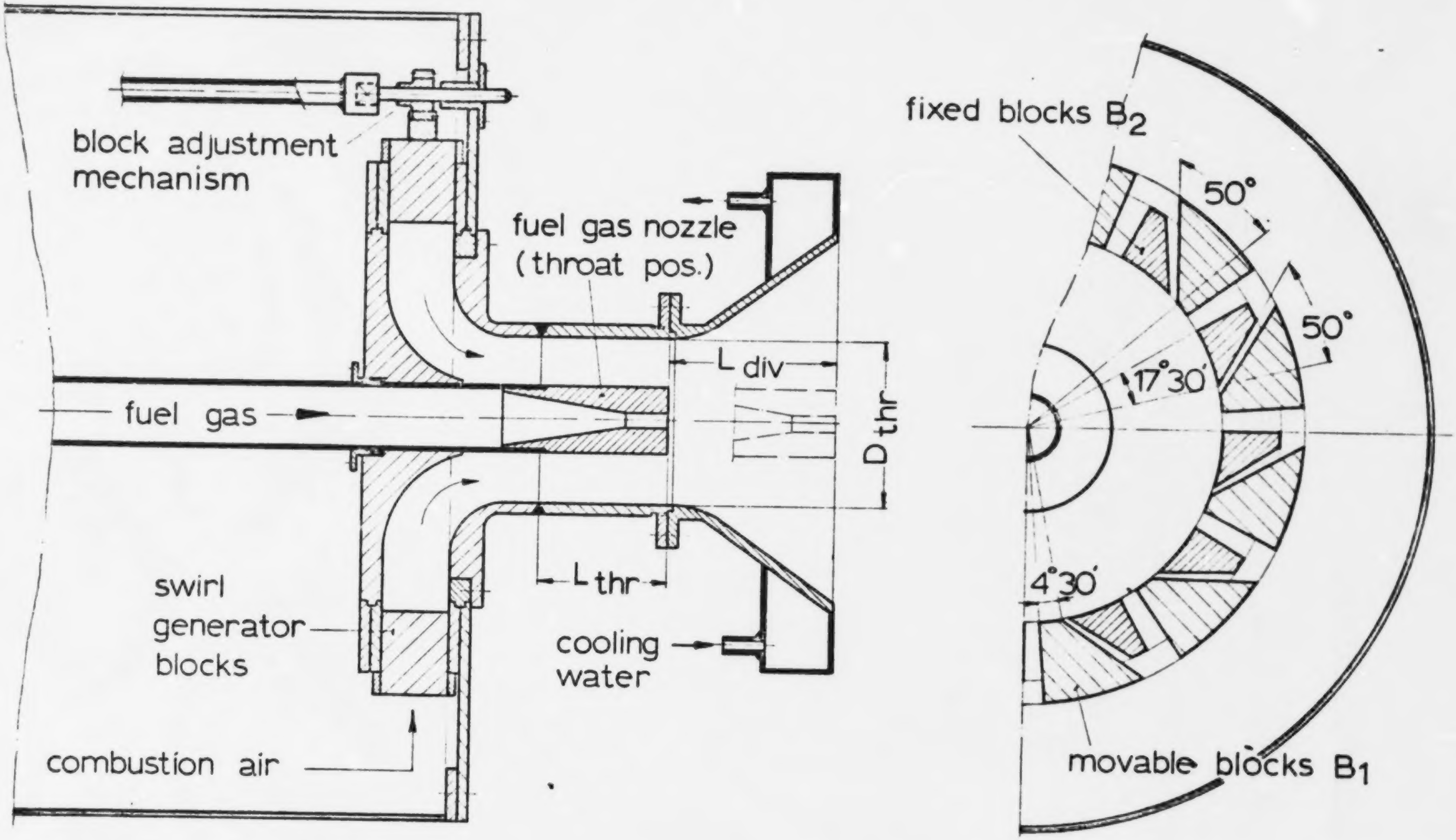
Coal

Volatile Content	32,68%
Ash	6,28%
C	78,48%
H_2	4,77%
N_2	1,05%
S	0,75%

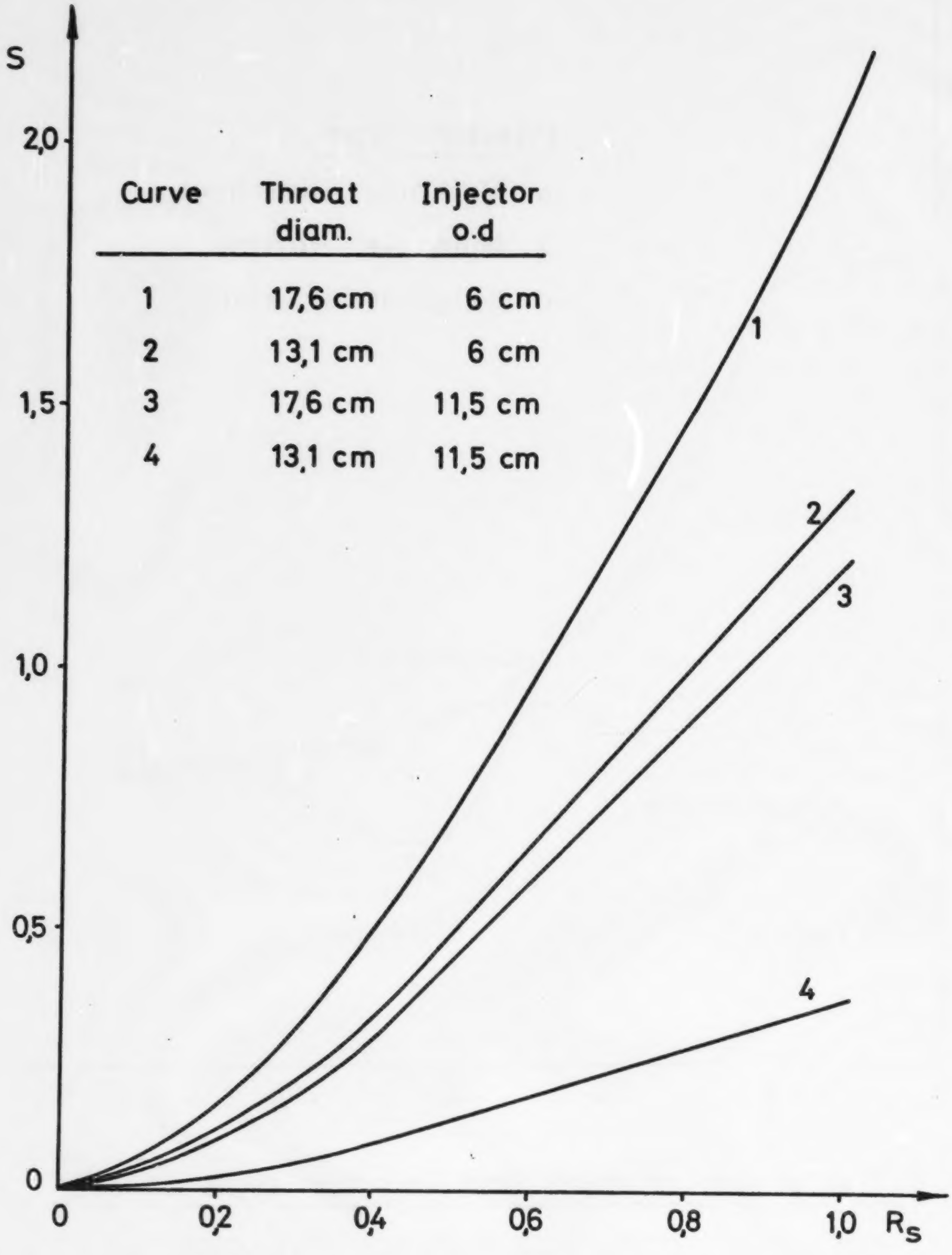
APPENDIX II.

COAL INJECTOR CHARACTERISTICS

Injector	Outside Diameter	Mean Primary Velocity m sec.$^{-1}$		
	cm.	10% Primary air	20% Primary air	30% Primary air
A	11,5	19	38	57
B	6,0	19	38	57
C	6,0	26	52	-
H	6,0	52	-	-


block adjustment mechanism
fuel gas nozzle (throat pos.)
fuel gas
L div
D thr
L thr
swirl generator blocks
cooling water
combustion air
fixed blocks B2
50°
50°
17°30'
4°30'
movable blocks B1

Fig·1: Moving block swirl burner



Curve	Throat diam.	Injector o.d
1	17,6 cm	6 cm
2	13,1 cm	6 cm
3	17,6 cm	11,5 cm
4	13,1 cm	11,5 cm

Fig. 2 : The relationship between relative swirl index R_S and swirl number S

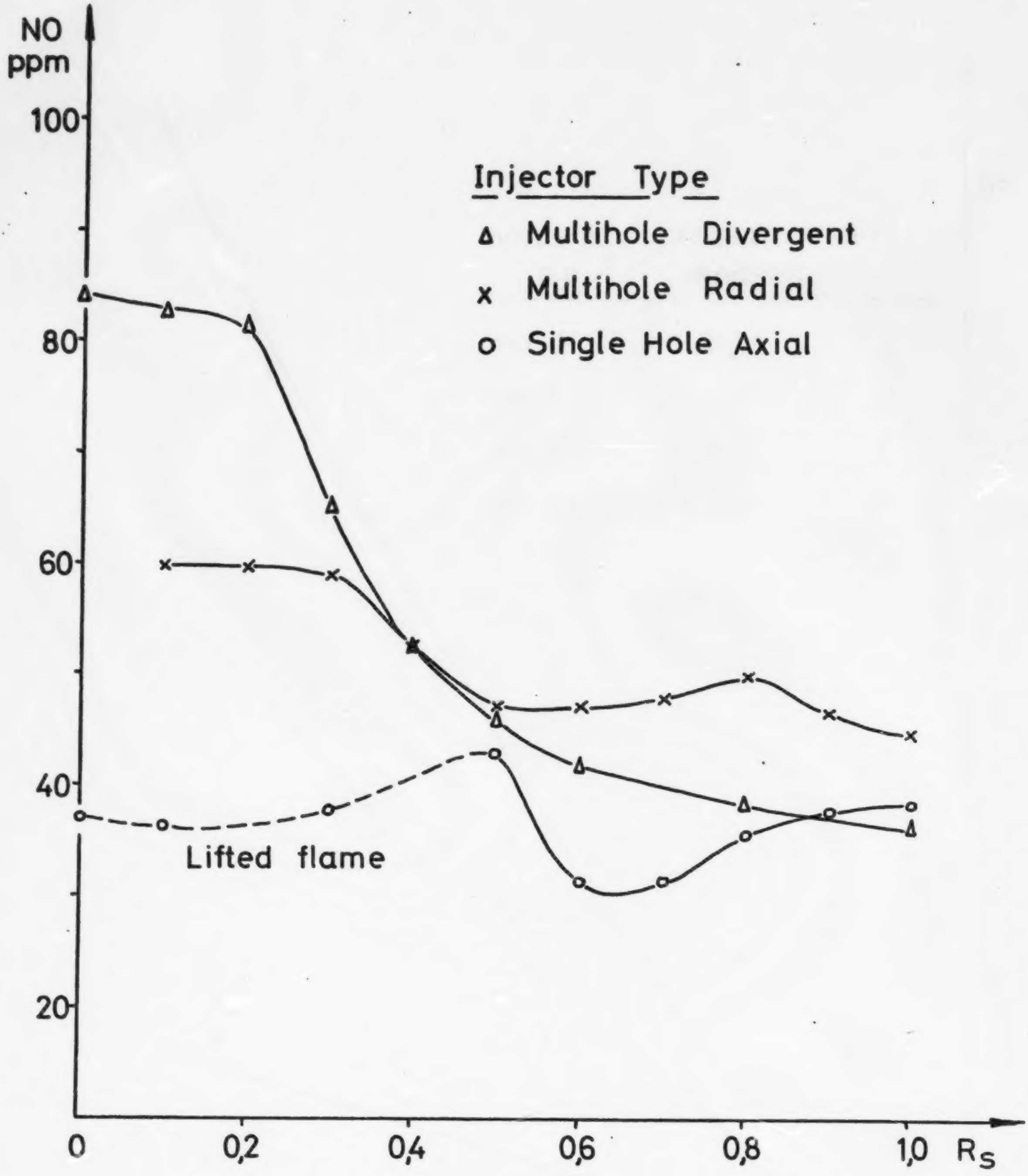


Fig. 3 : The effect of swirl and injector type on NO emissions from gas flames 5% excess air throat 17.6 cm diam injector in throat injector od 6,0 cm

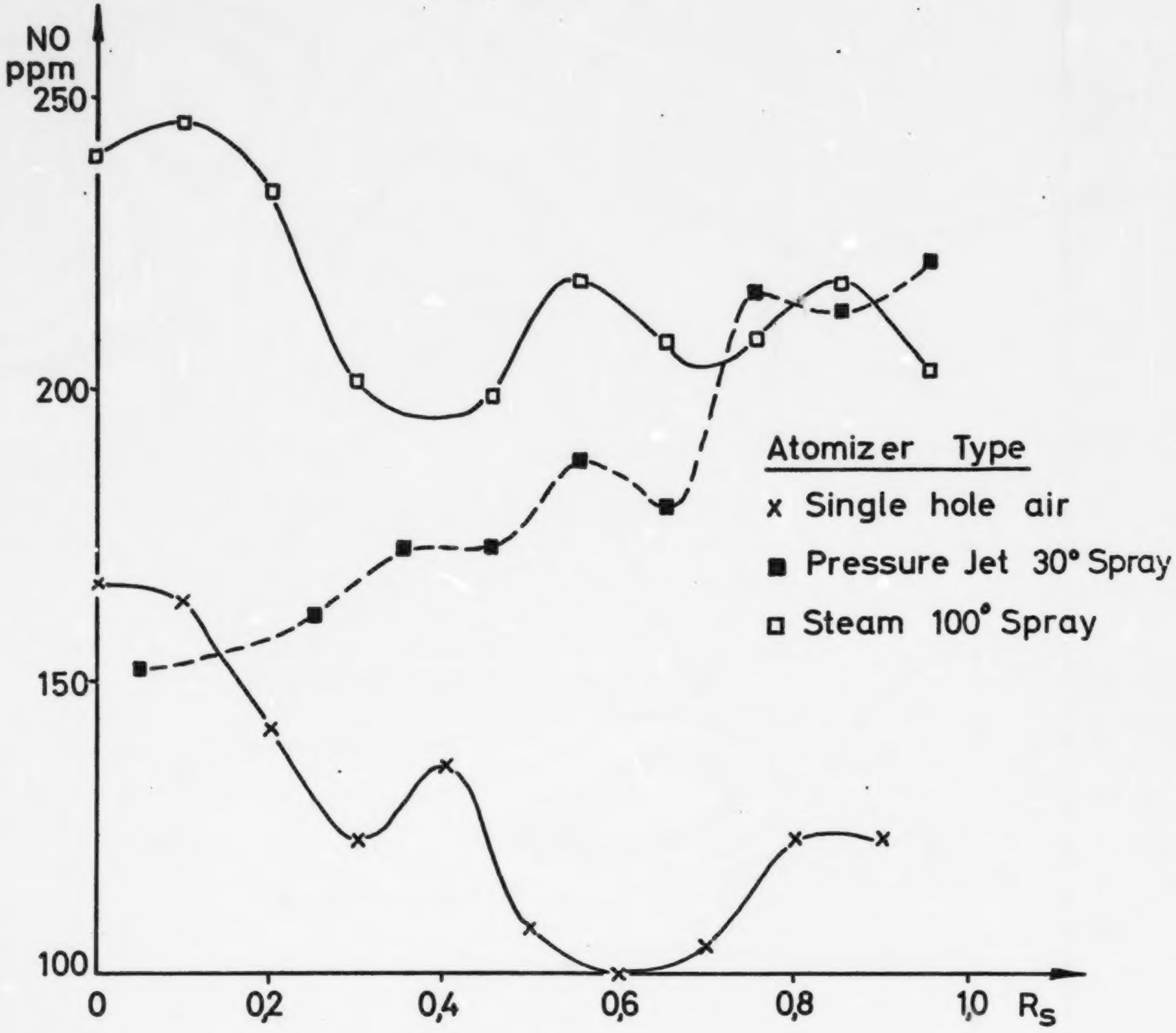


Fig. 4 : The effect of oil injector type and swirl on NO emissions (divergent 35° excess air 5% injector 6,0 cm o.d. in throat secondary air 30 °C)

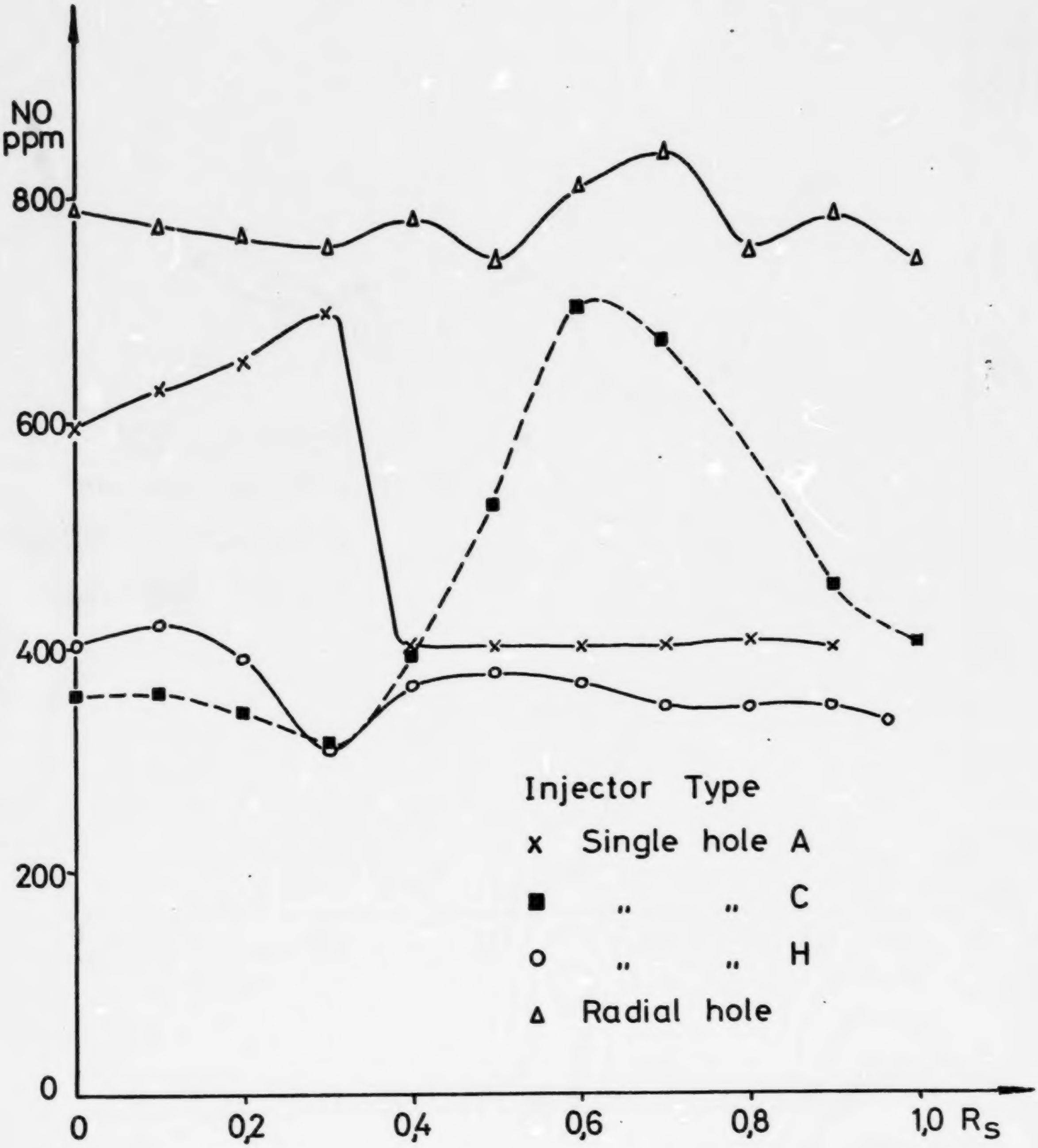
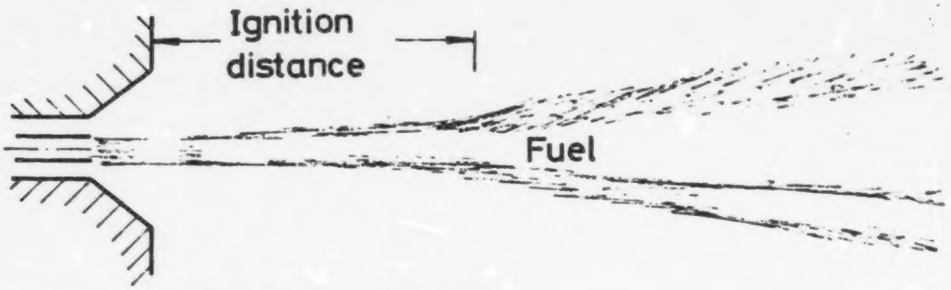
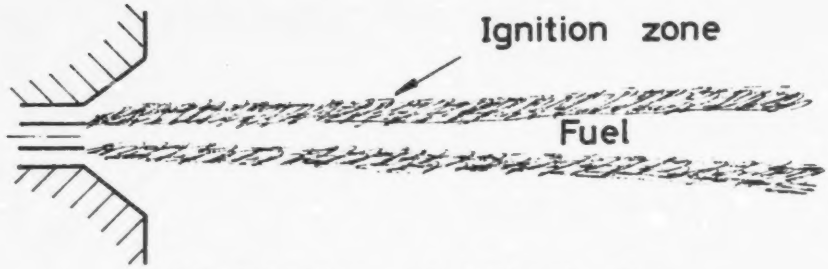


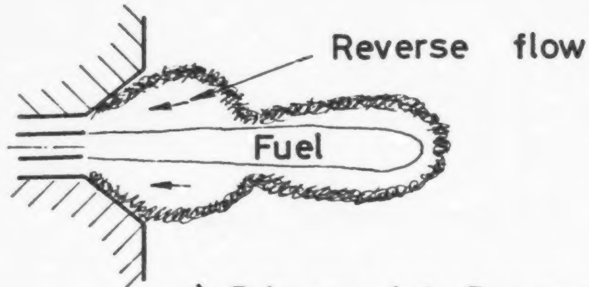
Fig. 5: Effect of swirl and injector type on the emission characteristics of P.F flames (300 °C preheat - 5% excess air)


Ignition distance
Fuel

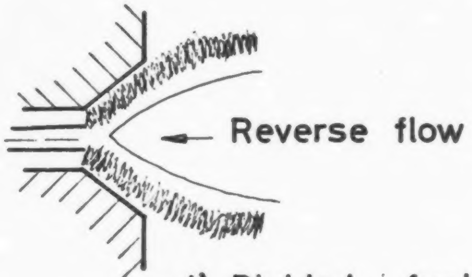
a) Lifted flames


Ignition zone
Fuel

b) Injector stabilised flame


Reverse flow
Fuel

c) Primary jet Penetrating Internal Reverse Flow


Reverse flow

d) Divided fuel jet

Fig. 6 : Simple Flame Classification Scheme

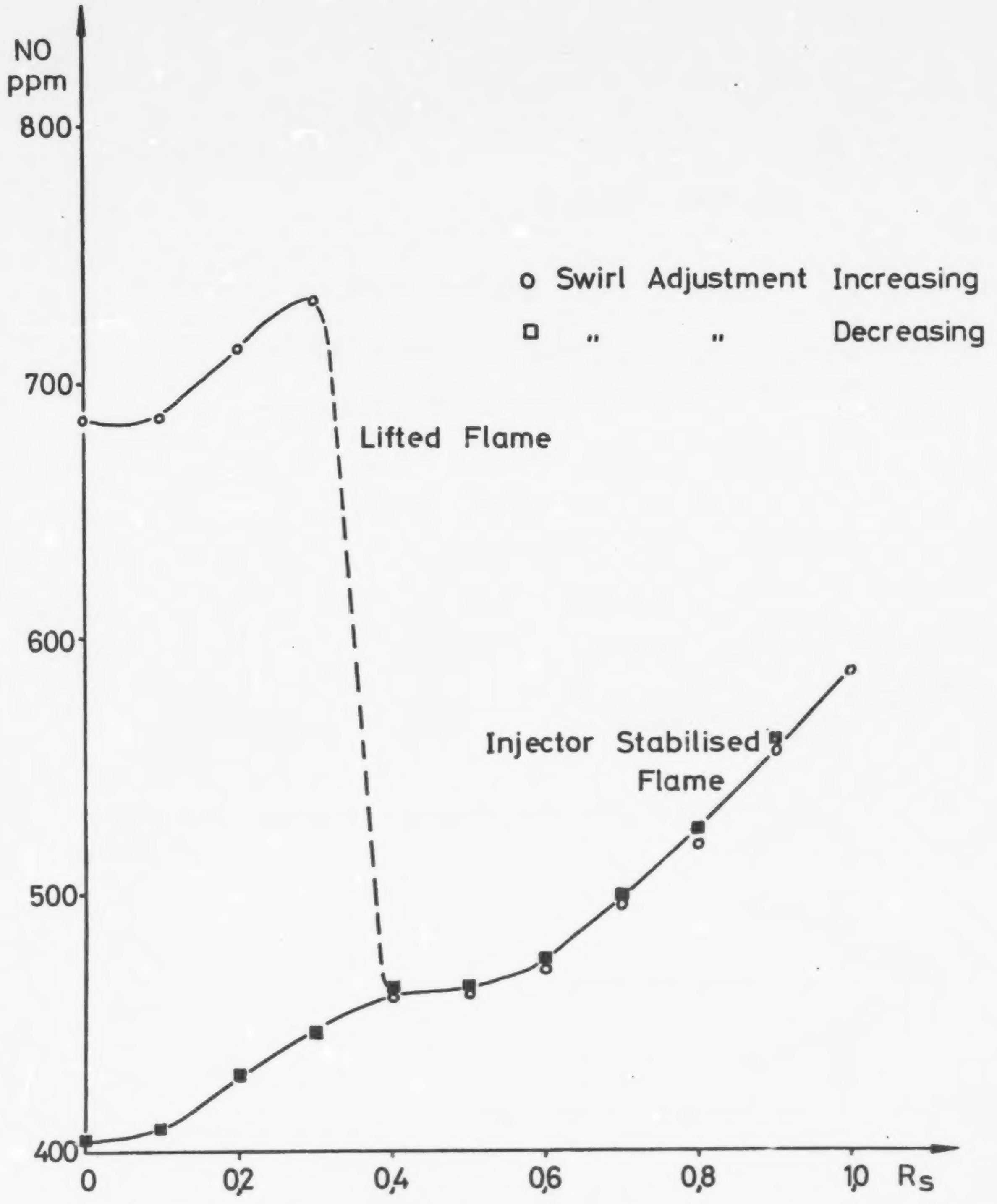


Fig. 7: Effect of stabilisation of ignition front on the injector (5% excess air 300 °C preheat injector o.d. 6,0 cm throat 17.6 cm diam)

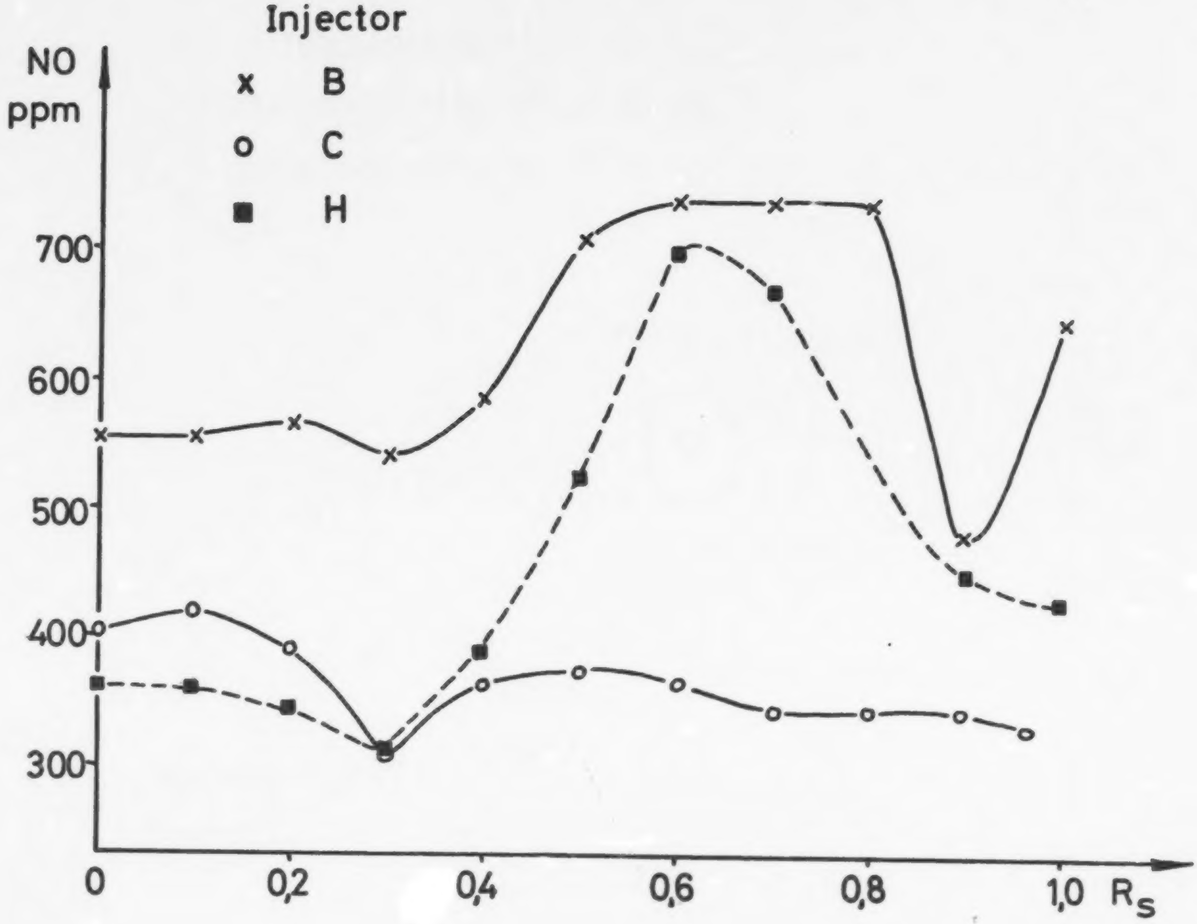


Fig. 8 : The effect of primary velocity (throat 17.6 cm diam.- 5% excess air - 300 °C preheat - primary air 10% of stoichiometric)

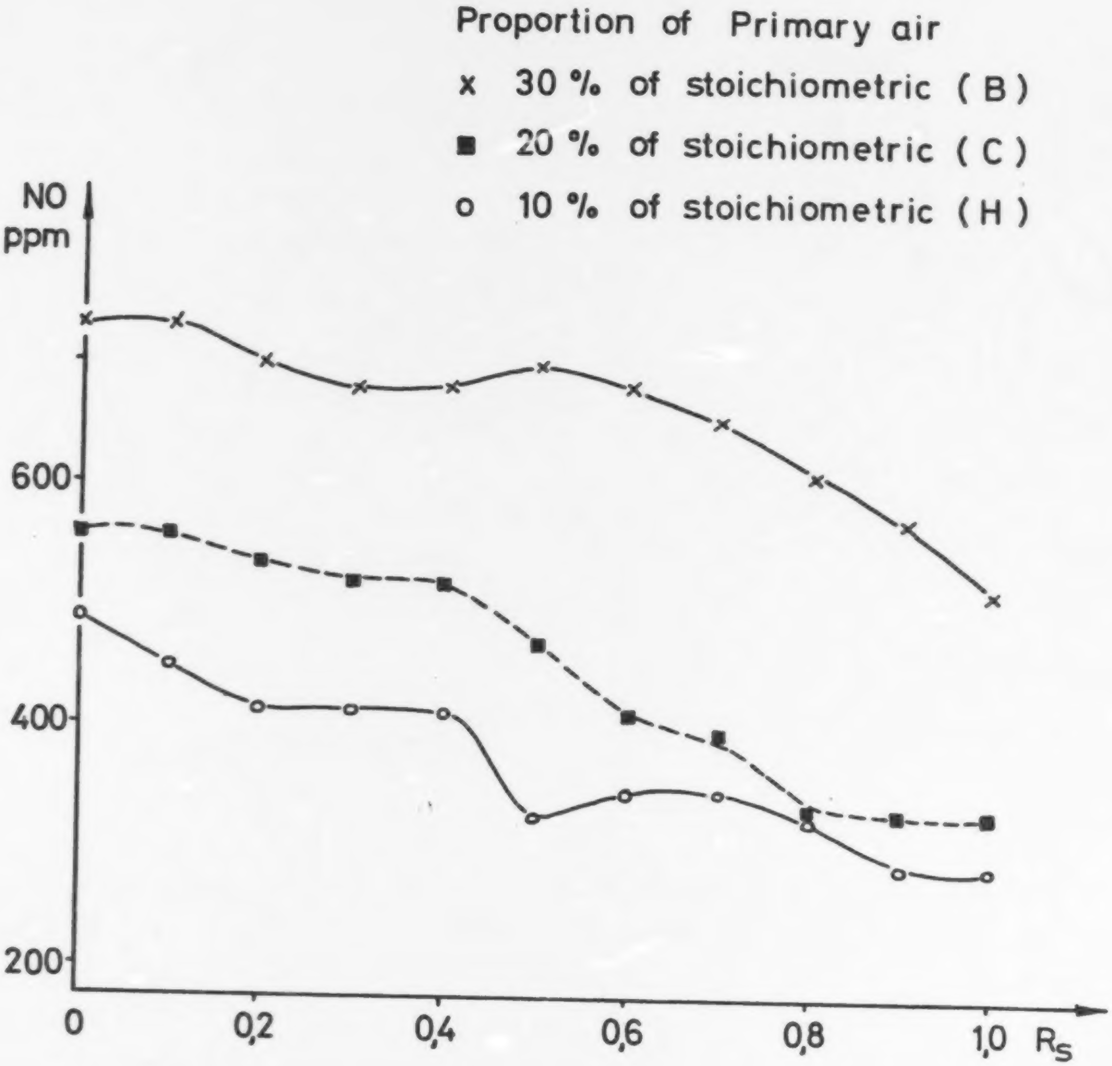


Fig. 9: Effect of primary air supply (throat 17,6cm diam - injector at throat - 5% excess air - 300°C preheat)

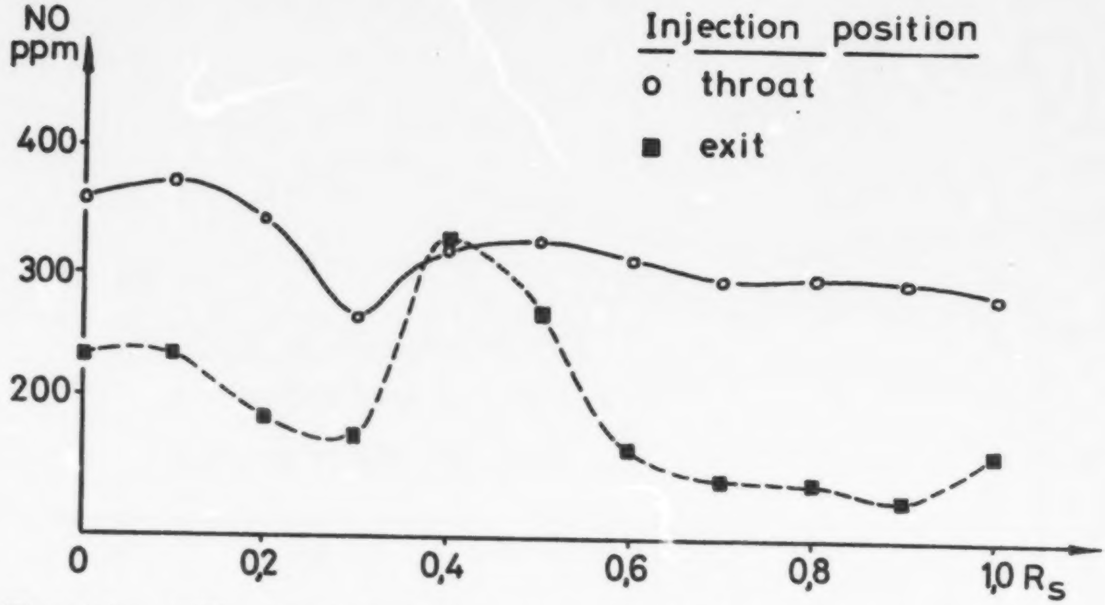


Fig. 10a : Effect of injection position (injector H - throat 17,6 cm diam - 5% excess air - 300 °C preheat - 10 % primary air

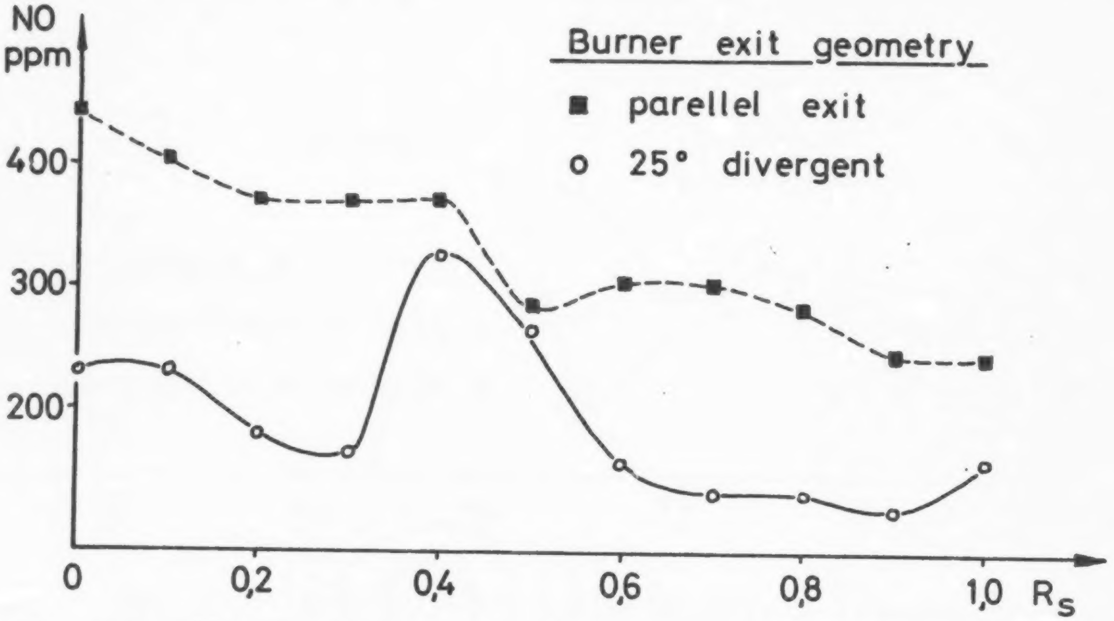


Fig. 10b : Effect of burner exit geometry (injector H at exit - throat 17,6 cm diam - 5% excess air - 300°C preheat 10% primary air

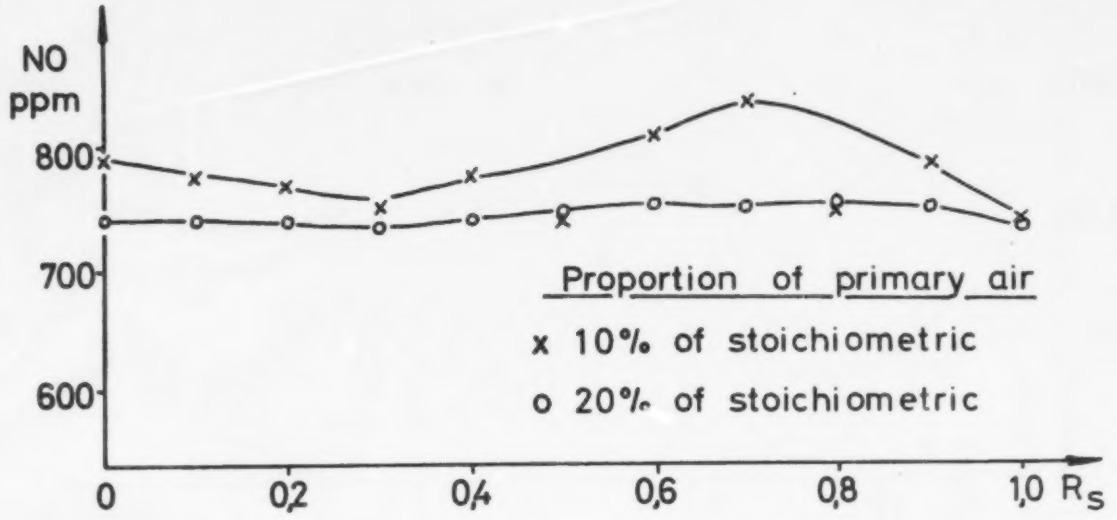


Fig.11 : Emission characteristics of divided fuel jet flames produced with a radial injector (injector 6,0 cm o.d. - throat 17.6 cm diam. - 5% excess air - 300°C preheat)

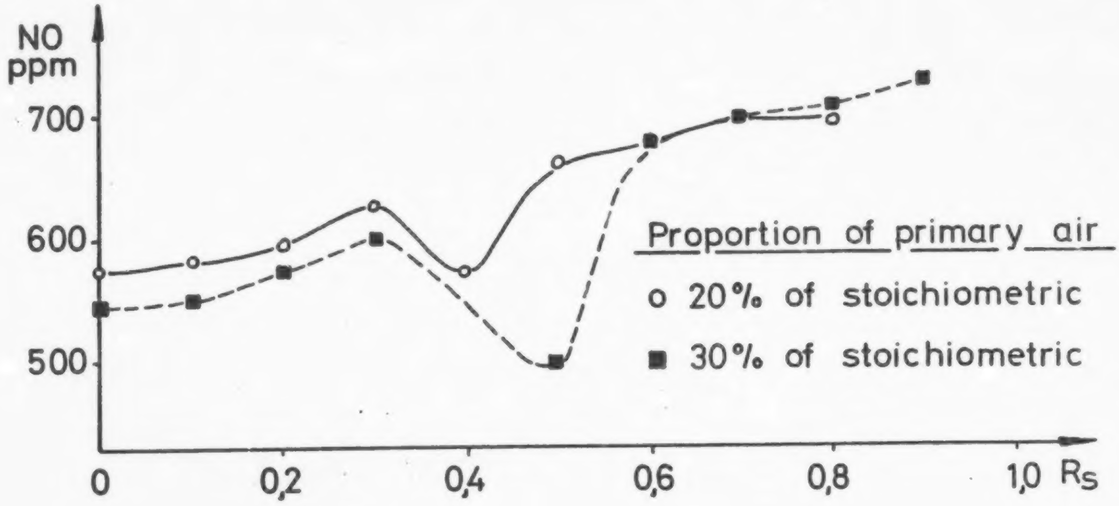


Fig.12 : Emission characteristics of divided fuel jet produced with an annular injector (injector 11.5 cm throat 17.6 cm diam - 5% excess air - 300°C preheat)

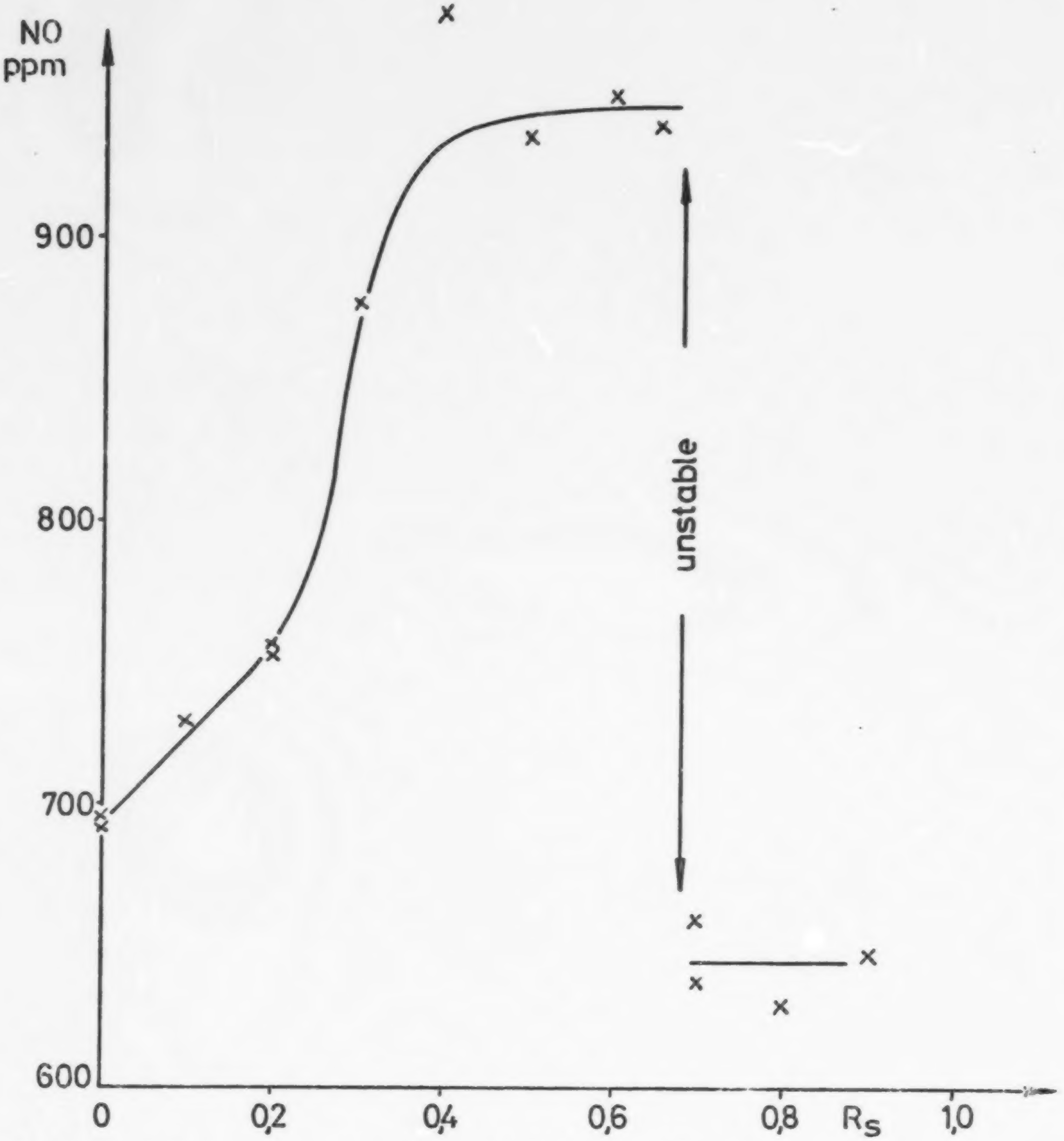


Fig. 13 : The effect of swirl on NO emissions with coal spreading device (300 °C preheat, - 15% excess air 25° divergent 17,6 cm id. throat injector 6,0 cm o.d. in throat)

NO_x REDUCTION TECHNIQUES
IN
PULVERIZED COAL COMBUSTION

by

Christopher England and John Houseman
Jet Propulsion Laboratory, Pasadena, California

(Presentation to the Pulverized Coal Combustion Seminar,
June 19-20, 1973, National Environmental Research Center,
Research Triangle Park, North Carolina)

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NO_x REDUCTION TECHNIQUES IN PULVERIZED COAL COMBUSTION*

by

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INTRODUCTION

The technology of the combustion of coal in utility boilers has been developed to optimize combustion efficiency, plant efficiency, and boiler lifetime. Increasing restrictions on emissions, however, require new procedures which balance overall efficiencies with emission control. Because flue gas treatment to remove low-level pollutants is generally uneconomical, other means are being sought to prevent the formation of undesirable compounds during the combustion process. These efforts center on fuel-processing to remove sulfur, ash and nitrogen compounds in the coal, and on combustion process modifications to prevent the formation of oxides of nitrogen.

Several studies have been made of the effect of low excess air operation (1, 2, 3) and staged combustion (4) on NO_x emissions from pulverized coal combustion, and all showed reduced emission levels with reduced excess air. Data are available, however, only over limited ranges of coal-air stoichiometry, primarily because of experimental difficulties in operating at rich or very lean conditions. Other combustion modifications designed to lower peak flame temperatures, such as reduced air preheat and product gas recirculation, have not been studied widely, and their effects are not fully understood.

The present paper describes a study in which coal was burned in a prefired tubular furnace in which air-fuel ratio and air preheat (both primary and secondary) could be varied routinely and independently to determine their effects on NO_x production. The purpose of the study was to obtain parametric data over

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*This paper presents the results of one phase of research carried out at the Jet Propulsion Laboratory, California Institute of Technology, under Contract No. NASA 7-100, sponsored by the National Aeronautics and Space Administration.

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the widest possible range of operating conditions to evaluate the effects of the various combustion process modifications on NO_x emissions.

EXPERIMENTAL APPARATUS

Furnace

Combustion was carried out in a horizontally-fired Mullite furnace tube with an inside diameter of 7.6 cm (3.0 in.) and an overall length of 154 cm (60 in.). The furnace was insulated with approximately 0.6 cm (0.25 in.) of zirconia fiber wrapping, and with approximately 5 cm (2.0 in.) of vermiculite packing (see Fig. 1). Pulverized coal was fed from a conventional vibrating screw feeder at a variable rate, usually from about 1.3 to 5.5 kg per hour (3 to 12 lb/hr). Coal was mixed with primary air by means of a jet ejector which used primary air as the working fluid. The amount of outside air inducted with the coal was determined by calibration without coal flow and by neglecting the influence of the solids on the induction rate. The coal-air mixture entered the furnace through a 2.5 cm (1.0 in.) diameter tube, the flow from which was interrupted by a bluff-body stabilizer as shown in Fig. 1. The stabilizer was used to increase combustion efficiency over that of coaxial injection. Secondary air was added from a concentric ring which introduced air uniformly into the furnace. Natural gas, used for prefiring, was introduced with the primary air. Both primary and secondary air streams could be preheated independently, with maximum capabilities of 66° C (150° F) and 400° C (750° F), respectively, at the 3.2 kg/hr (7 lb/hr) nominal feed rate. Coal and air feed rates were controlled remotely, the former by D.C. motor control on the screw feeder, and the latter by remote flow regulators which controlled the pressure behind critical flow metering orifices (see Fig. 2).

Sampling System

Chemical samples were taken at the furnace exit and analyzed by a non-dispersive infrared analyzer (NDIR) specifically for nitric oxide. A water-cooled quartz probe was used which separated particulates from the gas to be analyzed by inertial techniques. Figure 3 shows a schematic drawing of the probe. Dirty

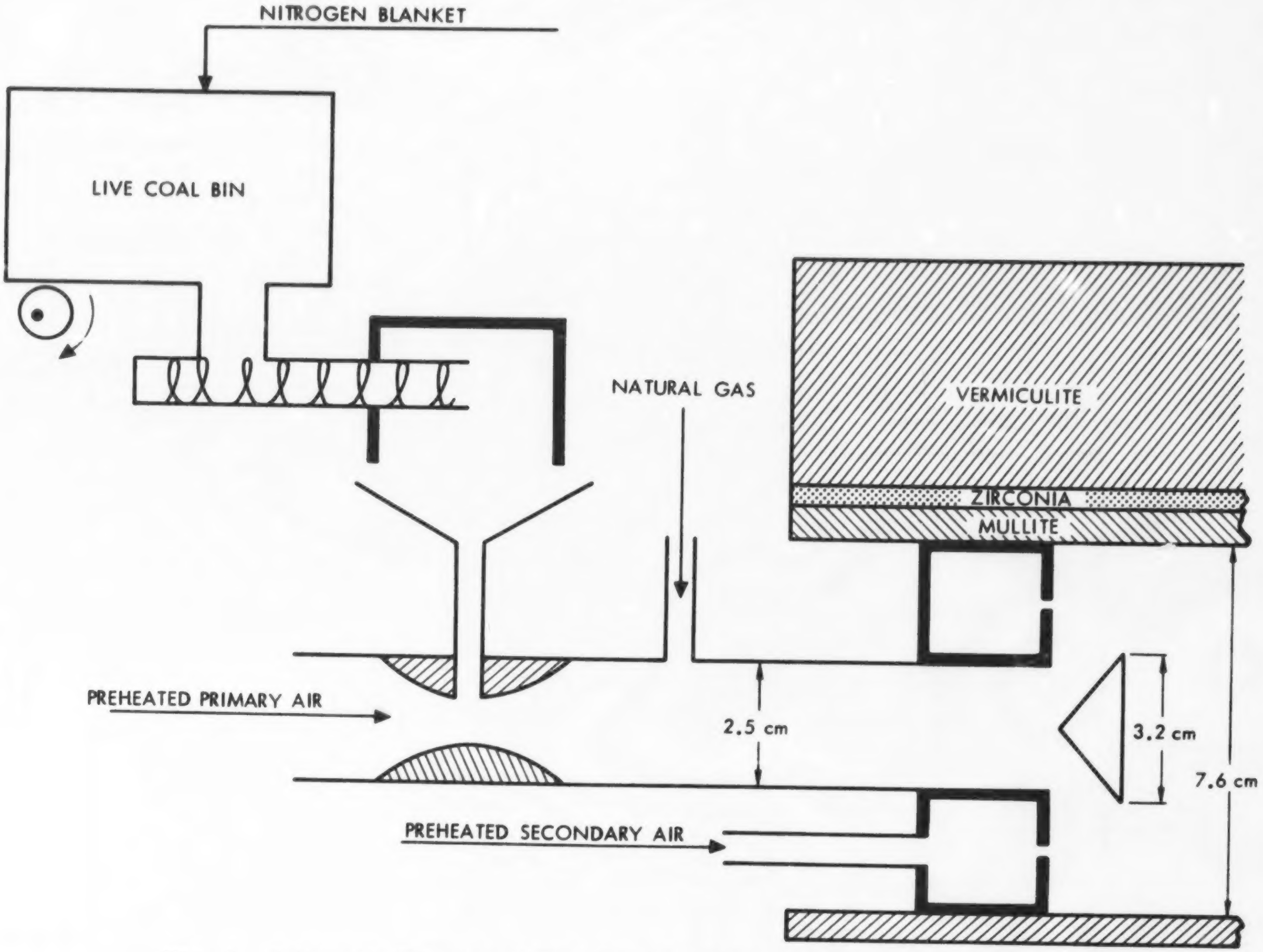
NITROGEN BLANKET
LIVE COAL BIN
NATURAL GAS
VERMICULITE
ZIRCONIA
MULLITE
PREHEATED PRIMARY AIR
2.5 cm
3.2 cm
7.6 cm
PREHEATED SECONDARY AIR

Fig. 1. Schematic Drawing of Coal Feeding Apparatus and Coal Burner

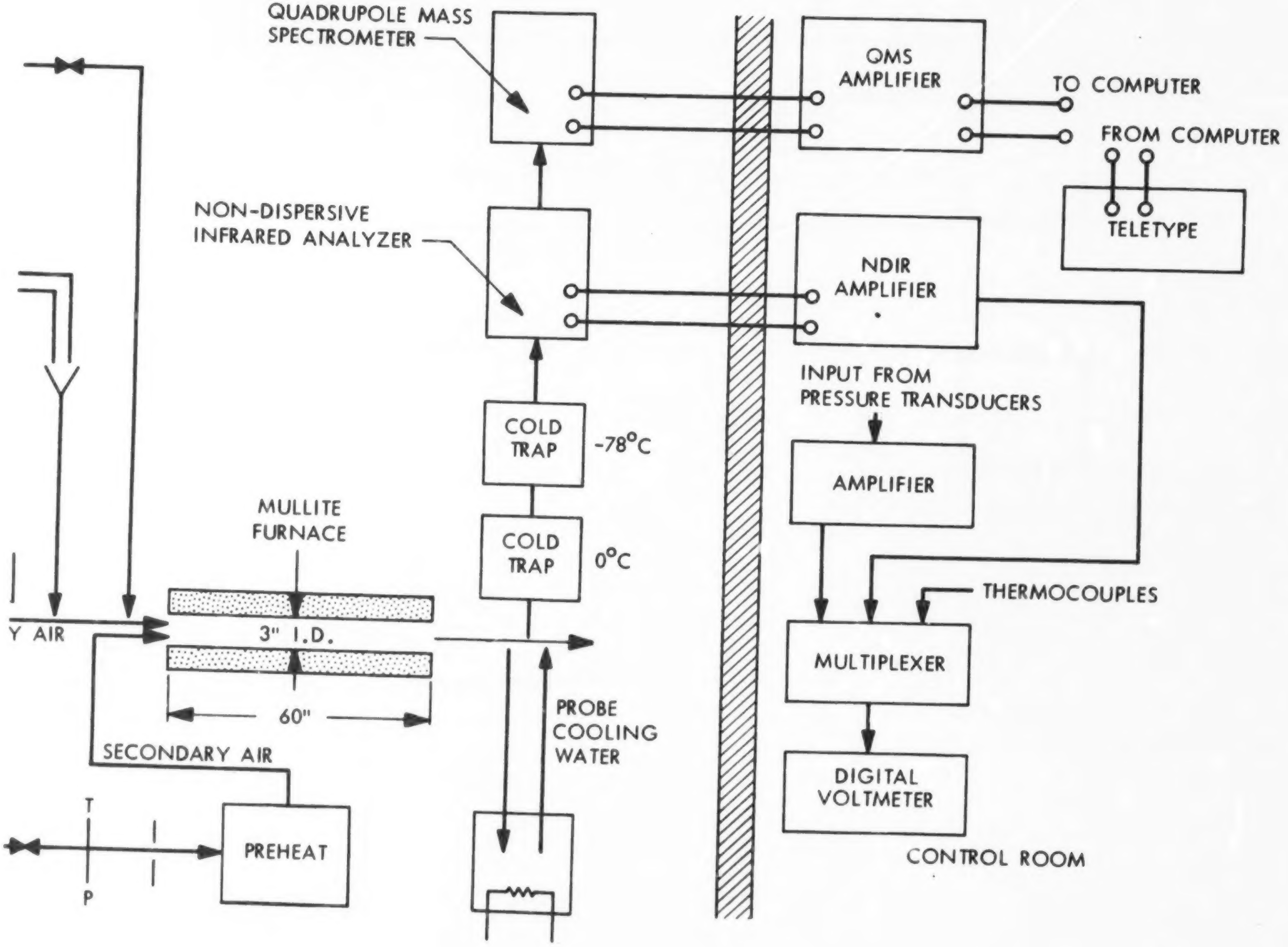
QUADRUPOLE MASS SPECTROMETER
NON-DISPERSIVE INFRARED ANALYZER
QMS AMPLIFIER
TO COMPUTER
FROM COMPUTER
TELETYPE
NDIR AMPLIFIER
INPUT FROM PRESSURE TRANSDUCERS
AMPLIFIER
THERMOCOUPLES
MULTIPLEXER
DIGITAL VOLTMETER
CONTROL ROOM
COLD TRAP
-78°C
COLD TRAP
0°C
MULLITE FURNACE
Y AIR
3" I.D.
60"
SECONDARY AIR
PROBE COOLING WATER
PREHEAT
T
P

Fig. 2. Schematic Drawing of Coal Combustion Apparatus and Instrumentation

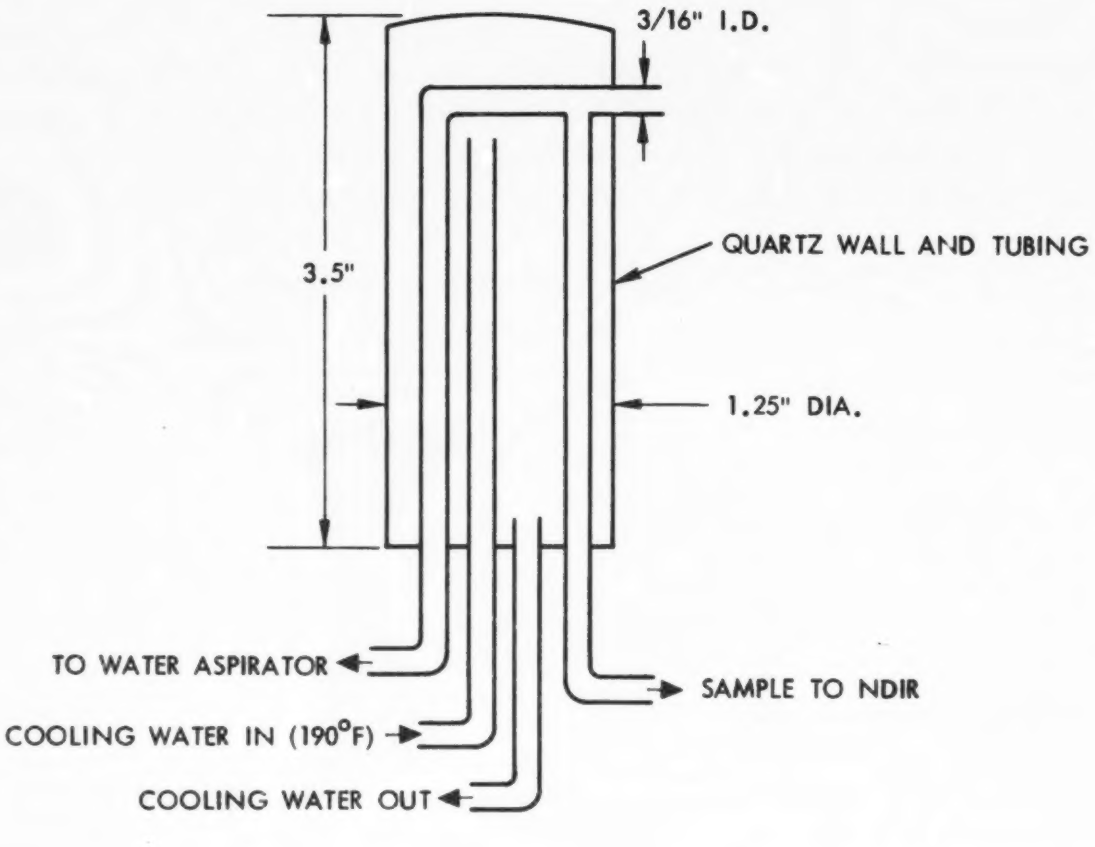
3/16" I.D.
QUARTZ WALL AND TUBING
3.5"
1.25" DIA.
TO WATER ASPIRATOR
SAMPLE TO NDIR
COOLING WATER IN (190°F)
COOLING WATER OUT

Fig. 3. Schematic Drawing of a Water-Cooled Dirty Gas Sampler

furnace gases were aspirated into the probe at a rate of about 40 ℓ/min, corresponding to a sampling velocity of about 30 m/sec. A particulate-free gas sample was withdrawn from this stream by pumping at right angles to the accelerated dirty sample stream. The sample rate of the clean gas stream was approximately 1.5 ℓ/min. Cooling water at 88° C (190° F) was circulated to prevent condensation of water in the probe. Clean gas samples were then dried by successive wet ice and dry ice cold traps, and analyzed by the NDIR.

Coal

The coal used in the study was from the Mojave field, and was supplied as a wet powder. The material was air-dried and sifted through a 160-mesh screen. The resulting powder was such that 70% passed through a 200-mesh screen. The ultimate analysis for this coal is given in Table 1.

Table 1. Ultimate Analysis of Mojave Coal

% C	68.3
% H	5.16
% S	1.0
% N	1.21
% O	23.4
% Ash	10.9
Btu/lb	9,520

Temperature Measurements

Furnace temperature was measured with platinum-platinum/10% rhodium thermocouples placed on the outside of the Mullite furnace tube. Thermocouples were placed at 2.5 cm (1 in.), 50 cm (20 in.) and 140 cm (54 in.) from the burner. In addition, a bare-wire thermocouple was placed in the exit plane gases to measure the temperature of the sample. The furnace temperature was taken as the middle (50 cm) thermocouple temperature. Air temperature measurements, both for air preheat and flow metering, were made with chromel-alumel thermocouples. All thermocouple readings were referenced to 65.56° C (150° F).

Experimental Procedure

The furnace was prefired with natural gas and preheated secondary air before each experimental point was taken. Upon achieving proper furnace temperatures, primary and secondary air flows were adjusted, the natural gas flow was stopped, and coal was introduced. Peak furnace temperatures from prefiring ranged from 1400° C (2550° F) to 1300° C (2370° F), depending on the level of secondary air preheat. The NO_x emission level was read when the furnace temperature dropped to the desired point.

EXPERIMENTAL RESULTS

Effect of Equivalence Ratio on NO_x

Both constant air flow and constant fuel flow tests were made to determine the influence of equivalence ratio (defined as fuel-to-air) on the formation of NO_x. In the case of constant air flow, the primary air rate was 1.37 kg/hr (30.2 lb/hr) and the secondary air rate was 28.2 kg/hr (64.3 lb/hr). At stoichiometric conditions (air-fuel ratio of 13.8), the coal feed rate was 3.11 kg/hr (6.85 lb/hr). The primary air preheat level was 65.6° C (150° F) while the secondary air was unheated and entered at 21° C (70° F). For tests with constant fuel flow, the coal feed rate was maintained at 3.52 kg/hr (7.75 lb/hr), the primary air remained constant at 13.7 kg/hr, and the secondary air was variable. In each case, data were taken when the furnace temperature fell to 2100° F.

Figure 4 compares the results of each method of operation on an as measured basis. For constant air flow, the level of NO_x increased steadily from 160 ppm at an equivalence ratio of 0.5 (200% theoretical air) to a maximum of 1160 ppm at an equivalence ratio of 1.8 (56% theoretical air). The NO_x-equivalence ratio profile was nearly linear and it appeared that the data may have reflected a counting of coal particles, with each particle contributing equally to NO_x production. The results with constant fuel flow, however, showed quite similar results, indicating that the effect was truly attributable to mixture ratio.

Figure 5 shows the same data but reduces the NO_x levels to an equivalence ratio of unity. This was done by dividing the NO_x value as measured by its

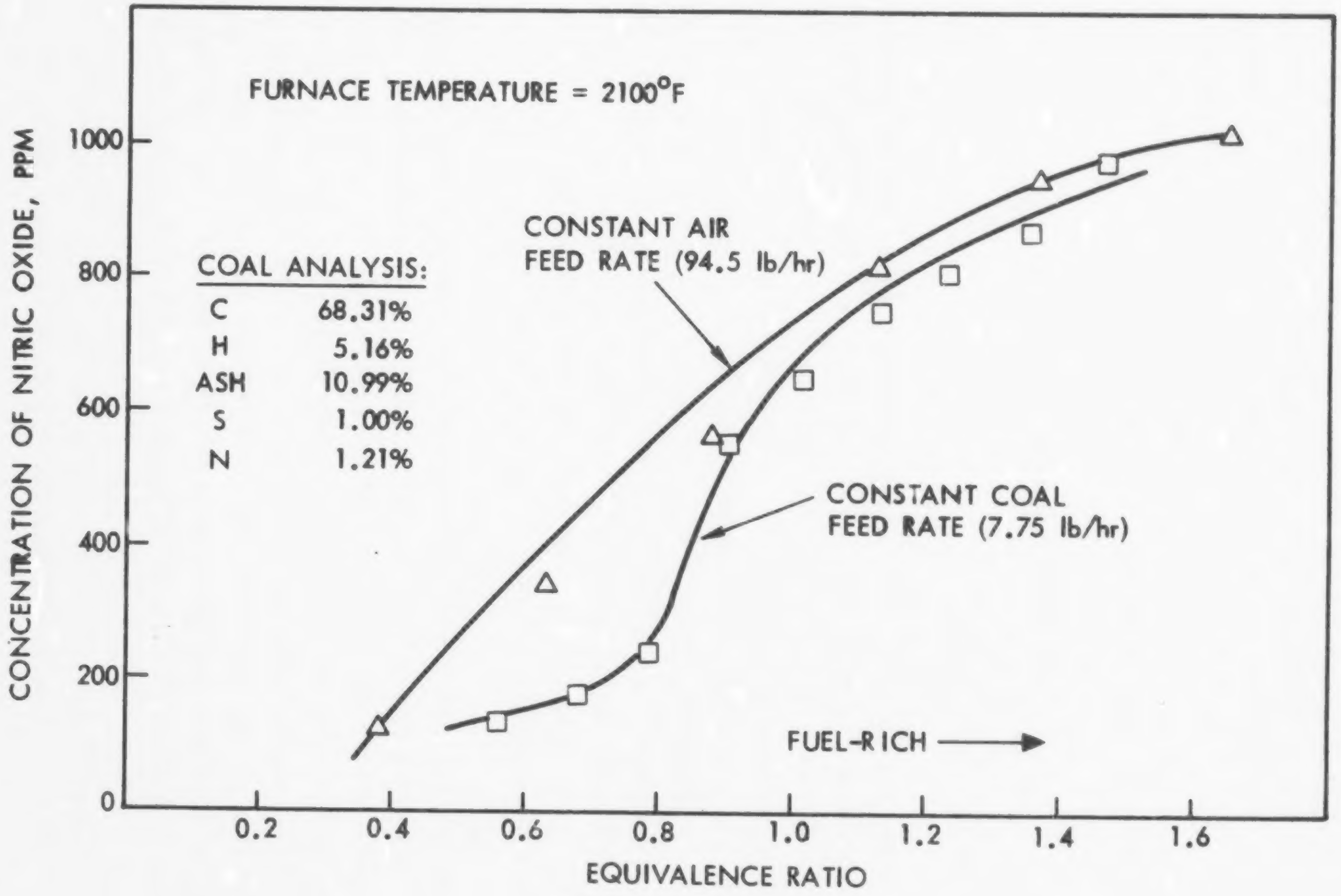

Fig. 4. Influence of Burner Equivalence Ratio and Furnace Operating Procedures on Nitric Oxide Emissions from Pulverized Coal Combustion

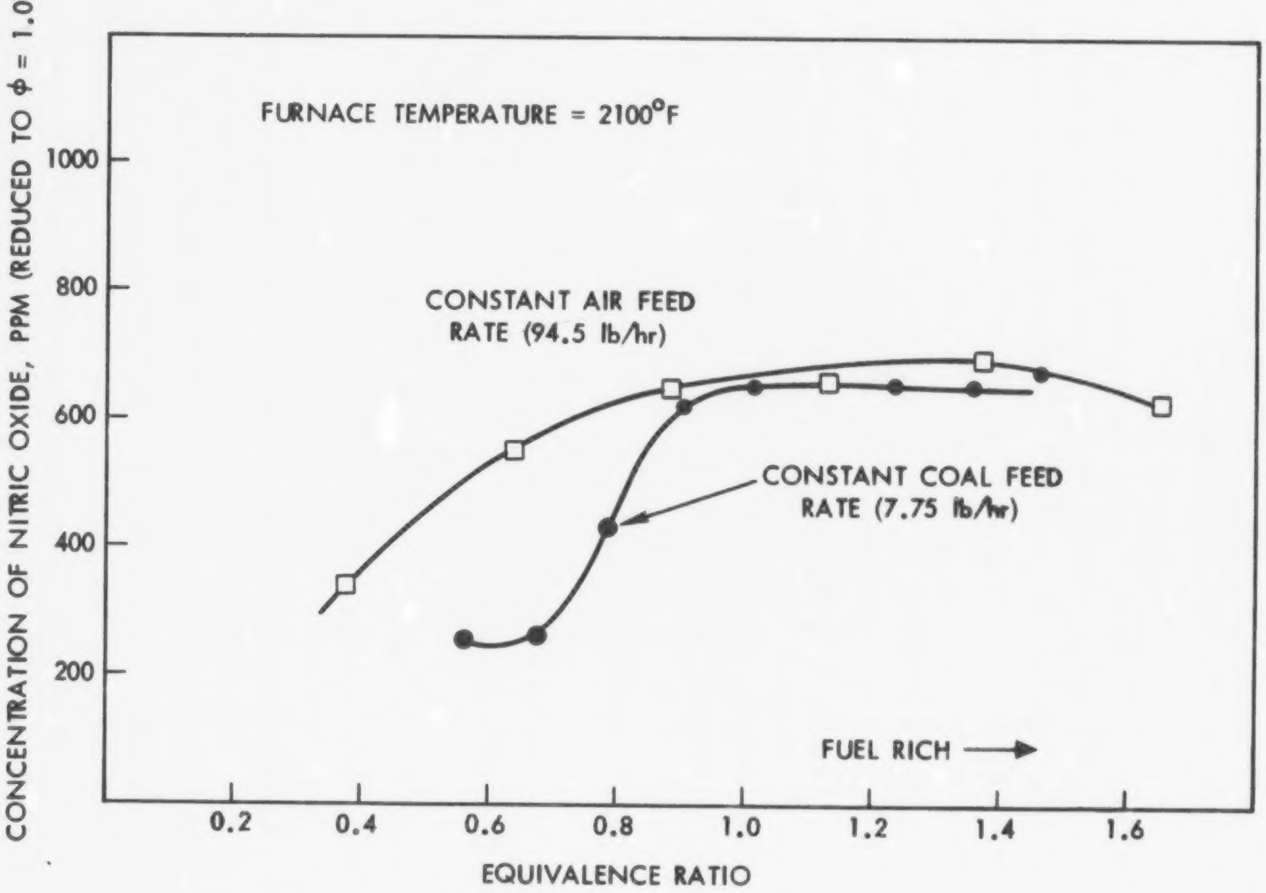

Fig. 5. Influence of Burner Equivalence Ratio and Furnace Operating Procedures on Nitric Oxide Emissions from Pulverized Coal Combustion

equivalence ratio. This procedure is accurate in air-rich flames where the oxidation product is primarily CO_2, but is not accurate in fuel-rich flames where the composition of the combustion gases is uncertain.

On a reduced basis, the level of NO_x was relatively low in the very lean flames, but approached a steady value of about 650 ppm between equivalence ratios of 0.9 and 1.8. The fuel-rich behavior was quite unexpected since one expects a reduction in both fuel nitrogen conversion and air nitrogen fixation in the overall reducing atmosphere of the fuel-rich flames. Since the same behavior was observed in both constant air and constant fuel operating modes, however, the effects must be attributed to those of air-fuel stoichiometry. For the Mojave coal, fuel nitrogen amounted to 1.21%, corresponding to nitric oxide levels of about 1550 ppm on a dry basis. It is possible that the constant 650 ppm level represents the volatile part of the fuel nitrogen, i.e., the fraction that burns first in an overall oxidizing atmosphere.

The Effect of Secondary Air Preheat

To test the influence of combustion air temperature on NO_x, the temperature of the secondary air was varied while holding the primary air preheat temperature constant at 65.6° C (150° F). The tests were run with a constant air feed rate with variable coal feed. Primary air represented 31% (13.7 kg/hr) of the total air, and the coal feed rate at stoichiometry was 3.1 kg/hr (6.85 lb/hr).

Figure 6 shows the results of tests over a range of equivalence ratios, and secondary air temperatures, but a constant furnace temperature of 2100° F. Secondary air preheat appears to have a strong influence on NO_x in very air-rich flames, with NO_x levels at an equivalence ratio of 0.5 (200% theoretical air) ranging from 450 ppm without preheat to 1250 with 343° C (650° F) preheat. All NO_x-equivalence ratio profiles, however, converged on the 650 ppm level in fuel-rich flames. At an equivalence ratio of 0.8 (125% theoretical air) where industry prefers to operate, the reduction in NO_x with secondary air preheat amounted to 38% as the secondary air preheat dropped from 343° C (650° F) to 21° C (70° F). The primary air was preheated only to 66° C (150° F) and represented almost a third of the total air. Thus, the average air preheat at 343° C (650° F) secondary air preheat was approximately 257° C (495° F).

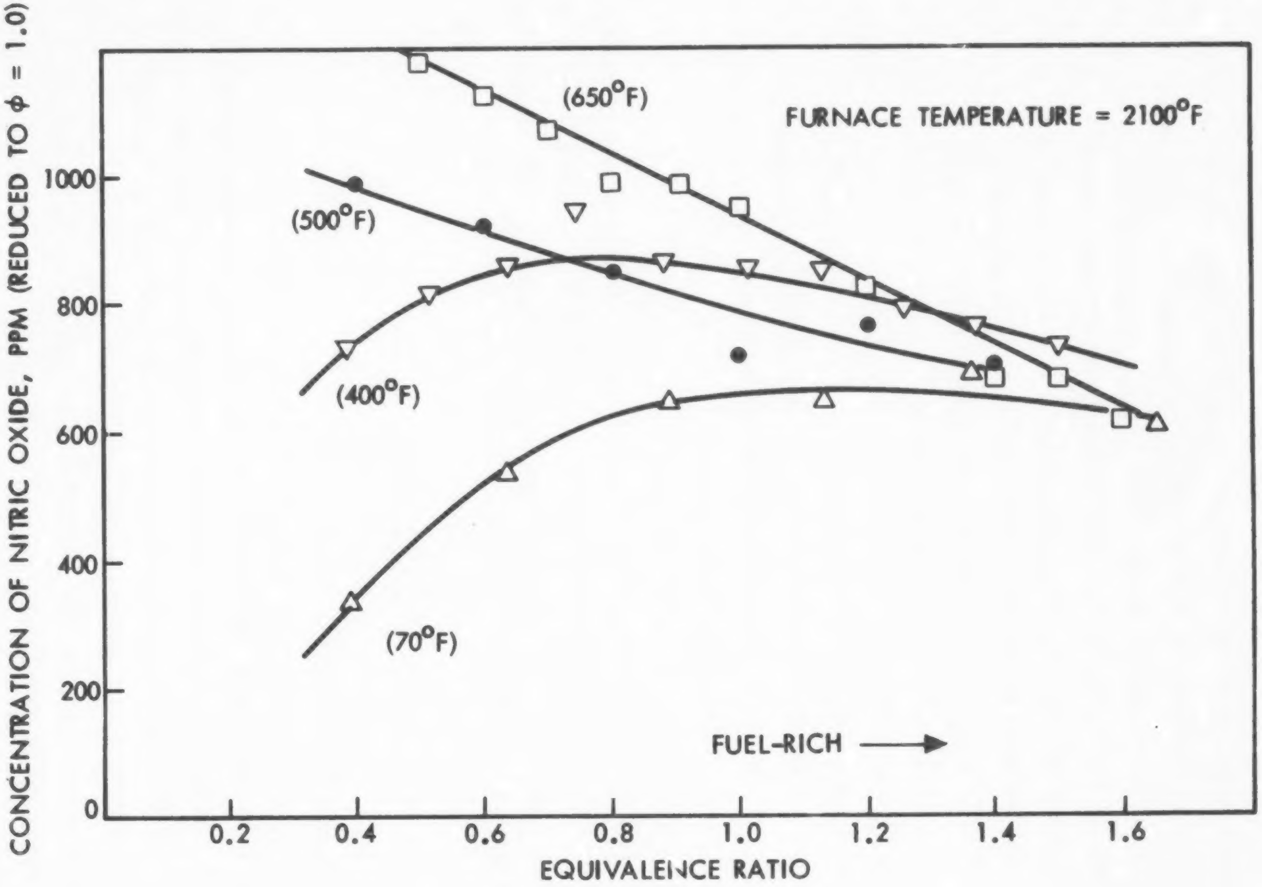

Fig. 6. Influence of Burner Equivalence Ratio and Secondary Air Preheat on Nitric Oxide Emissions from Pulverized Coal Combustion

The Effect of Furnace Temperature

The prefired furnace was designed to operate over a very wide range of stoichiometry, and, as a result, had a high surface-to-volume ratio (0.526 cm^{-1}) relative to other furnaces of similar throughput. Thus, the effect of furnace wall temperature would be magnified in this furnace if, indeed, the wall temperature influenced NO_x formation. Figure 7 shows the results of tests with 343° C secondary air preheat at three air-coal mixtures. As expected, lower furnace temperatures lower NO_x emissions, but the reduction from 1200° C (2200° F) to 870° C (1600° F) was only 22%. Bienstock et al. (1) showed similar results correlating the effect of primary zone flame temperature on NO_x formation. While their measured NO_x levels were lower, a 20% reduction in NO_x was observed for the same (600° F) reduction in measured flame temperature. They observed, however, that the effect of temperature from 1200° C (2200° F) to 1425° C (2600° F) was quite large.

The effect of furnace wall temperature was greater at the lean conditions than at stoichiometric conditions. This was probably due to the lesser heat release rate at the lean conditions. The nominal heat release rate at stoichiometric conditions was 2.66×10^9 cal/hr m^2 (300,000 Btu/hr ft^3).

DISCUSSION

The Influence of Furnace Design

The results shown were obtained in a coal furnace of fixed burner design and with a short residence time for combustion gases. The average residence time in the furnace at stoichiometry and with a coal feed rate of 3.1 kg/hr was about 0.6 sec, which was not nearly sufficient for char burnout. Thus, the results pertain primarily to the NO_x formed near the primary flame zone. The absolute NO_x levels were relatively high in this study, and this can be attributed to the lack of sufficient residence time for the NO_x to dissociate at lower furnace temperatures. Bienstock, et al. (1) noted a rather large relaxation in NO_x levels as the combustion gases traveled through their more conventional furnace, and attributed these to dissociation of NO. It is also possible that reactions during char burnout lower the NO_x substantially.

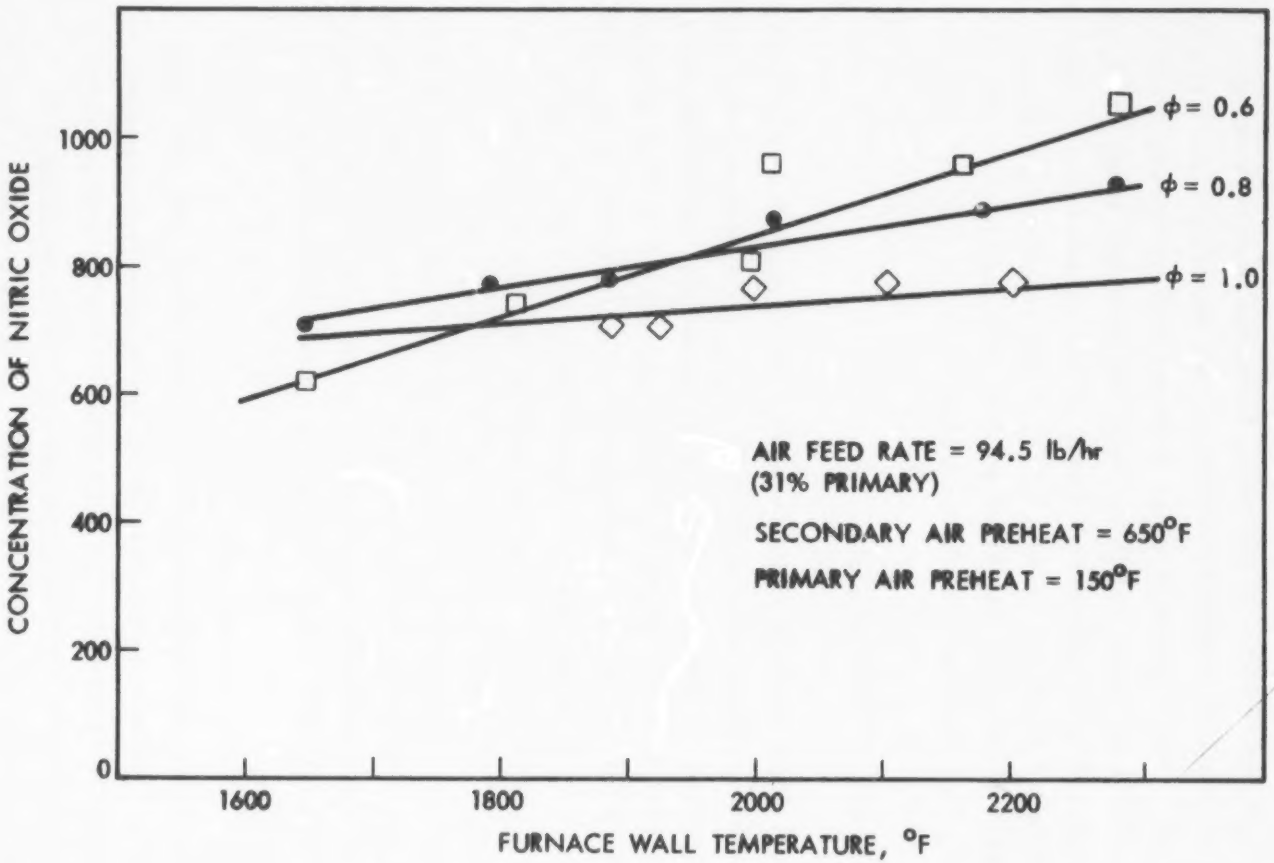

Fig. 7. Influence of Furnace Wall Temperature and Burner Equivalence Ratio on Nitric Oxide Emissions from Pulverized Coal Combustion

The configuration of the burner is known to be an important factor in NO_x formation (5). The purpose of the present work, however, was to make a parametric study of combustion modifications only, with possible burner design studies to be made later. In the present case, primary and secondary air injection occurred in close proximity, and it is likely that both air streams were well-mixed before combustion commenced. Thus, in the present design, one probably would not expect a large influence on NO_x of the relative flow rates of the two air streams. In addition, air preheat could probably be considered as an average primary and secondary air temperature.

The Influence of Combustion Modifications

Low excess air firing generally reduces emissions of nitric oxide in both boiler operation (6) and in research furnaces (1, 2, 3, 4). Data in highly fuel-rich flames has not been available, however, and only a limited amount of data have been presented on the effects of air preheat. The results shown in Fig. 6 indicate that, while the air-rich NO_x characteristics of the coal-air flame are highly dependent on secondary air preheat, NO_x from stoichiometric and fuel-rich flames is relatively independent of both preheat and air-coal ratio. These results are quite different from those from similar tests on gas and oil firing where moderately fuel-rich operation results in sharp reduction in NO_x. The level of NO_x in fuel-rich coal flames corresponds to about 42% of the NO_x that would be found with 100% fuel nitrogen conversion. Coincidentally, it has been reported that the volatile fraction of fuel nitrogen is about 40% of the total in some pulverized fuels (3).

It is suggested that NO_x emissions in near-stoichiometric and fuel-rich flames are due almost exclusively to conversion of the volatile fuel nitrogen to nitric oxide. The volatile fraction of the coal is burned in an overall oxidizing atmosphere as long as the overall burner stoichiometry is below about 2.5 (corresponding to stoichiometry with 40% volatiles). In these flames, conversion of gaseous fuel nitrogen is high, and NO_x emissions, reduced to stoichiometric, are relatively independent of coal-air ratio and air preheat. At overall burner stoichiometries in the air-rich region, emissions of NO_x are strongly dependent on secondary air preheat, indicating that the flame temperature in these regions dominates both fuel nitrogen conversion and molecular nitrogen conversion.

This view of NO_x formation in pulverized coal flames indicates two alternatives to NO_x control by combustion modifications. First, NO_x can be reduced by reducing combustion temperature of the volatiles. This can be accomplished by product gas recirculation, water injection, or similar methods designed to vitiate the initial fuel-air mixture. Second, NO_x can be reduced by burning the volatiles at overall burner equivalence ratios greater than 2.5. This can be accomplished by limiting primary air to substantially less than 25% of the total required for combustion.

ACKNOWLEDGEMENT

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6. Dr. J. Shapiro, Bechtel Corporation, Personal Communication, June 1972.

PILOT AND FULL SCALE TESTS

PART I

The Effect of Design and Operation Variables on NO_x Formation in Coal Fired Furnaces

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Presented to
Pulverized Coal Combustion Seminar
National Environmental Research Center
Research Triangle Park, North Carolina
June 19-20, 1973

Sponsored by
Environmental Protection Agency
Research Triangle Park, North Carolina
Contract No. 68-02-0634

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THE EFFECT OF DESIGN AND OPERATION VARIABLES ON NO_x FORMATION IN COAL FIRED FURNACES

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Sponsored by Environmental Protection Agency,
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Contract No. 68-02-0634

I. INTRODUCTION

The purpose of this EPA contract is to determine the effectiveness of methods of NO_x control which can be used on coal fired utility boilers, present and future. In addition, we wish to identify potential problems in boiler operation and thermal efficiency. A comparison of the relative effectiveness of these combustion control methods is also to be made for gas and oil.

The contract is divided into three phases which are defined below:

- Phase I - Identification of important variables in NO_x control and qualitative determination of change in NO_x emission levels with change in each method of combustion control separately (6-month effort, now finished using a single burner unit).
- Phase II - Quantitative correlation of the trends found in Phase I and determination of the extent of interdependence of variables (6-month effort which will include construction of a multiburner unit for use in Phase III).
- Phase III - Verification and expansion of the quantitative correlations found in Phase II using the new multiburner unit (12-month effort due to start about January, 1974).

The basic combustion tunnel used for testing in Phase I is a single burner unit which fires ~ 227 kg hr^{-1} of coal (~500 lb/hr) at normal load. The coal used in Phase I had a combustion enthalpy of 6.67 kcal g^{-1} (12,000 Btu/lb) dry and this corresponded to a heat release rate in the active furnace volume of 390,000 kcal m^{-3} hr^{-1} (~44,000 Btu/ft^3/hr). The total heat release rate is ~ 1.4×10^6 kcal hr^{-1} (~ 5.6×10^6 Btu/hr).

There are two types of control for the reduction of NO_x which can be used: operational control techniques and design methods. Operational control techniques are more easily applied to existing units; the physical change on the unit is minimized and the cost of the change will be lower. Design methods would be applied to new units yet to be constructed; thus a minimum of redesign/reconstruction costs would be entailed. The operational variables that have been studied in Phase I are: (1) excess air, (2) firing rate of the fuel (or unit load), (3) preheat of the air, and (4) swirl (for natural gas firing only). The design variables included in Phase 1 studies were: (1) flue gas recirculation, (2) two-stage combustion, (3) fuel type (gas, coal, or oil), and (4) heat removal rate from the combustion gases (quench).

II. UNIT DESIGN

The basic combustion unit used for the Phase I tests (Figure 1) is a cylindrical tunnel 1.4 meters (4.5 feet) in diameter and 2.4 meters (8 feet) in length with an overall effective furnace volume of 3.60 m^3 (127 ft^3). The fuel and air normally enter into the furnace together through the burner area. For coal transport, about 15% of the rated load total air carries the coal into the furnace through the central fuel pipe; this air is defined as the primary air. The balance of the combustion air normally enters the furnace around the center pipe and is defined as the secondary air. With gas, there is no primary air and oil is steam atomized so that again there is no primary air.

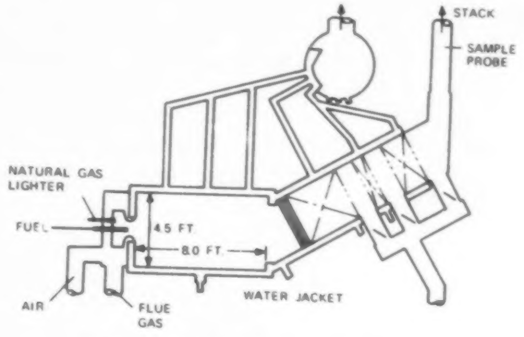

FIGURE 1. BASIC COMBUSTION UNIT (SINGLE BURNER)

There are two slot positions for two-stage combustion in the front and side of the furnace (Figures 2 and 3). The two front slots are cut 3" by 12"; the 1" on either side of the center 1" x 12" opening is bricked in. The front slots are arranged so that the second stage air enters parallel to the burner axis. The combined inlet area of the front slots is one half of the burner inlet area.

The two side slots for two-stage combustion are cut 6" by 6" and bricked 2" on either side of the 2" x 6" opening. The side slots add the second stage air perpendicular to the burner axis and are offset circumferentially to create a swirling action. The combined inlet area of the side slots is the same as the front slots.

The coal burner (Figure 4) consists of a pipe with concentric pieces of flared welded sheet metal at the end to spread the coal into the secondary air. The burner arrangement used during most of the tests consisted of six fixed (non-moveable), curved vanes in the burner throat to add some swirl to the secondary air. The coal spreader is normally just at the inside entrance to the throat during firing. At other positions further into the throat, the flame leaves the burner and travels partway down the furnace.

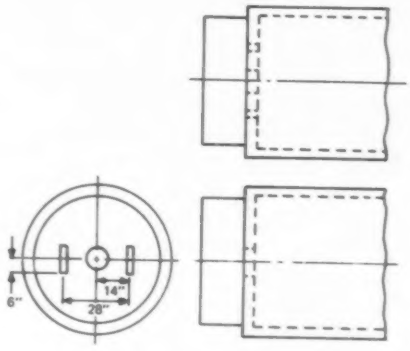

FIGURE 2. FRONT SLOT POSITIONS

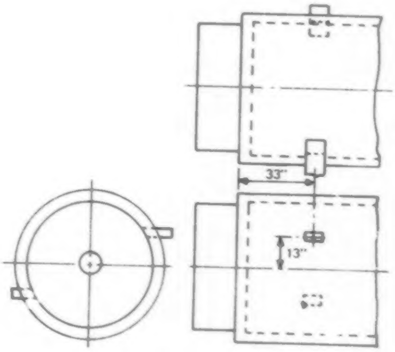

FIGURE 3. SIDE SLOT POSITIONS

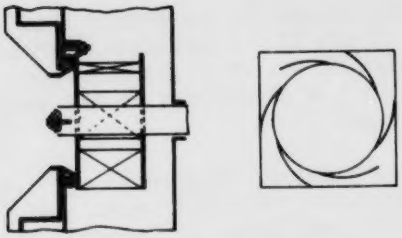

FIGURE 4. COAL BURNER

The natural gas igniter is left on during all coal firing tests to ensure that ignition is maintained in the furnace, especially during unstable combustion conditions. The flow is set at 20% full gas flow for the igniter, but this flow of gas supplies less than 1% of the total heat release at normal loads. Under reduced loads, it is less than 2% of the total heat release in the furnace.

The gas burner (Figure 5) is a supply ring with eight equally spaced spuds for gas inlet into the throat. There is a split washer about 1" from the tip of the spud which serves the purpose of holding the flame. Next to the washer are two sets of holes drilled diametrically opposed. The two sets are side by side on the burner axis. The holes are oriented for all eight spuds so that the gas exits tangent to an imaginary circle which is approximately one half of the burner diameter.

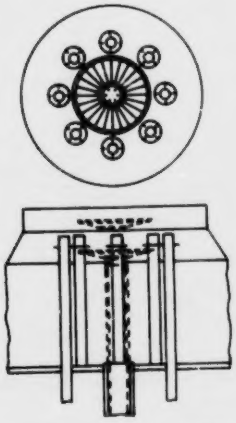

FIGURE 5. GAS BURNER

The secondary air swirler used for gas and oil firing is a set of 16 moveable vanes which can be set from 0°, or no swirl, to about 30°, or maximum swirl. Only the gas flame remained ignited in a stable manner at no swirl; the coal flame left the burner at lower swirl angles (less than 20° to 30°) and went out or was half-way down the furnace under no swirl (0° to 10°).

The dual fluid oil burner (Figure 6) employs steam as the atomizing medium and consists of three concentric pipes mounted on the axis of the burner. The outermost pipe holds the impeller which is a conical slotted disk of sheet metal with the vanes bent to create a slight swirl. The innermost pipe carries the steam and the middle pipe carries the oil. There is an atomizer tip on the end of the two inner pipes (Figure 7). The center hole in the atomizer (Y-jet) carries the steam and the No. 6 oil, which is preheated to retain fluidity, is in the branched opening which enters the steam jet.

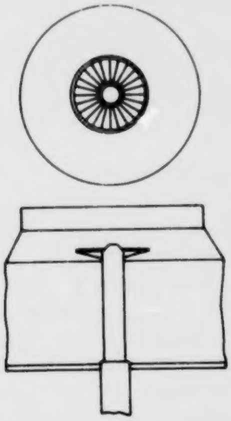

FIGURE 6. OIL BURNER

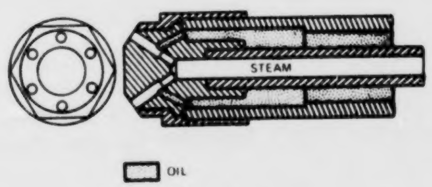

FIGURE 7. OIL ATOMIZER

III. INSTRUMENTATION

The flue gas is sampled in the stack where the average temperature is down to less than 500°K (450°F). A stainless steel probe extends half-way across the stack. The gas sample is passed through a condenser maintained at 283°K (50°F) and then is split and monitored by the following instrumentation (Figure 8):

(1) An MSA LIRA CO analyzer (measuring from 0 to 5000 ppm)

(2) A Whittaker SO_2 analyzer of the chemical cell type (0 to 5000 ppm)

(3) An MSA paramagnetic O_2 analyzer (0 to 25%)

(4) A Bailey O_2 Meter (0 to 10%) and total combustibles (0 to 5%) hot wire analyzer.

(5) A TECo (Thermo Electron Corp.) chemiluminescence NO_x monitor (0 to 10,000 ppm)

(6) Whittaker NO_x chemical cell analyzer (0 to 5000 ppm) with a Mallcosorb column

(7) A Beckman NDIR for NO (0 to 1500 ppm)

The Beckman NDIR requires the use of another ice bath maintained at a constant 274°K (34°F exactly, ±0.5°F) to remove a maximum amount of water. Even so, enough water remains in the gas to be measured so that a 60 ppm correction must be made to the final measurement as a residual H_2O correction.

The gases used for the NO_x calibrations are certified calibration gases from Matheson containing about 200, 500, 800, and 1200 ppm NO (less than 5 - 20 ppm NO_2) in N_2. The gases, when purchased, are checked against the previous standards before being put into regular use.

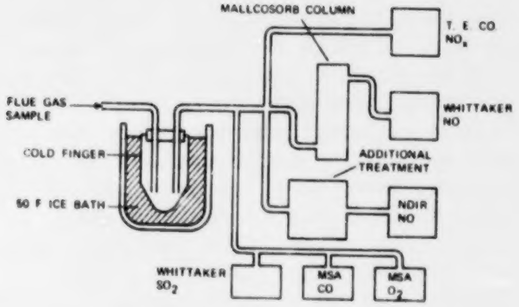

FIGURE 8. INSTRUMENTATION

IV. TEST PROGRAM

The test program for Phase I called for identification of the major variables for NO_x control. The major variables to be investigated were divided into design and operational variables. Design variables were expected to be more easily implemented in new units not yet built. In order to change existing units, the expense would be very great when compared to modifying operational conditions. It might also be physically or economically impractical to modify existing units. The design variables, therefore, suggest that physical and mechanical changes could be made in the unit and would include flue gas recirculation, staged combustion, quench rate, and basic fuel type. On the other hand, it would prove less expensive to modify the operational variables for existing units such as excess air, fuel firing rate, air preheat, and swirl. (These groups of variables are not meant to be mutually exclusive).

Since the basic contract fuel requirement was for coal firing, limited tests with gas and oil were used for comparison with the coal results under the same furnace conditions. The burner configuration for the coal was changed from the fixed 6-vane burner to the variable angle 16-vane burner only once in an attempt to study the effect of swirl on coal combustion. Base tests with coal through either burner showed less than 10% variation in NO_x emission levels.

V. RESULTS

The objective of the initial phase of this investigation was to establish relative effects of changes in operational and design variables. Hence, an attempt was made to hold other conditions constant and to change the variable under study over a wide range. However, many of these are interrelated, hence as load, excess air, preheat, staged combustion, flue gas recirculation and the other variables were changed, air velocities changed leading to a variation in mix rate, turbulence and combustion intensity. To date, no attempt has been made to interrelate these variables, but an attempt to do so is projected as a part of Phase III.

During operations, continuous measurements were made of O_2 (two instruments), CO, combustibles, SO_2, and NO (three instruments). The measurements were all recorded on strip chart recorders. On random occasions, about 20% of the time, ash loadings in the stack gases were obtained for determination of unburned carbon.

When surveying a single variable, generally the extremes and the middle of the range were tested. The trends were determined in this way. However, it should be emphasized that in many cases, the extremes on a single variable are beyond the range of what is considered acceptable operating practice. Furthermore, it should be emphasized that these results apply to a small single burner test unit. Although it is believed that the trends shown will probably hold for a large multiburner furnace, the magnitude of the changes may be appreciably different; also, some of the test variables may not be operationally acceptable on large units.

The effect of each single variable will be discussed below. In the case where absolute measurements of NO emission levels are shown, a single test (or two) to verify proper instrumentation operation was made and the test runs for data collection were made. But, when relative measurements of NO emission levels are shown, the tests were run in pairs. The base line test and the data test were run in the same day to eliminate possible day-to-day variations. The NO reduction was then calculated by comparing the change in NO emission level to the emission level in the base line test.

A. Excess Air

Figure 9 shows the effect of excess air at rated load with 600 - 650°K (600 - 700°F) air preheat on NO emission for natural gas (no fuel-bound nitrogen), #6 fuel oil (0.23% fuel-bound nitrogen), and coal (1.1% fuel-bound nitrogen). The relative positions of the curves with coal highest, gas intermediate, and oil slightly below gas agrees in general with data from field units. However, the natural gas and oil NO emission levels fall in a low range and one explanation for this is the fairly conservative rating (furnace heat liberation rate) for these fuels in our test unit.

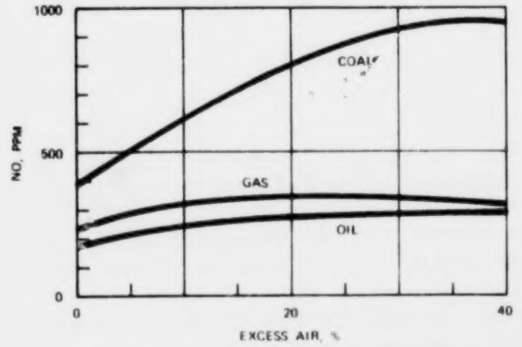

FIGURE 9. EFFECT OF EXCESS AIR ON NO_x

The NO emission from gas is a result of thermal fixation of atmospheric nitrogen. The degree of thermal fixation of N_2 into NO depends on temperature and excess oxygen level. At lower excess air levels, the effect of increasing the oxygen level more than offsets the decrease in temperature, hence the rising curve. In addition, at low excess air, the flame can be more luminous and this may lead to a more rapid quench rate. At higher excess air, eventually the decreasing temperature becomes the overriding effect and the curve drops again after reaching a maximum.

In contrast, the coal contains fuel-bound nitrogen and the conversion of this represents a second source of NO. It is expected that the differences in the shape of the curve and peak position when compared to the gas curve is a result of the fuel-bound nitrogen conversion. The trend shows a correlation of higher fuel-bound nitrogen conversion to NO with higher excess air levels. The evidence for this is shown in a steeper slope to the NO curve at lower excess air levels and a peak position at higher excess air level. It is not felt at this stage in the program that the fuel-bound nitrogen conversion can yet be quantitatively evaluated.

The initial thought for oil is that this curve should be higher than gas due to the fuel-bound nitrogen content. In our unit, oil burns with a more luminous flame than gas and has a larger visible flame envelope. Hence, the lower NO levels from oil are attributed to better radiating properties and therefore a lower bulk gas temperature.

B. Load

The dependence of coal NO emissions on load is illustrated in Figure 10. There is no indication of a peak level being reached under these conditions. Gas and oil NO levels show only a slight dependence on firing rate. Again it should be pointed out that with the burner arrangement used in these tests, the air velocity through the burner and the turbulence change with load.

Also to be considered is the refractory shielding in the front of the furnace. This probably means that there is less response of NO to load than would be obtained with a higher quench rate.

C. Preheat

The dependence of NO emission level on air preheat can be seen in Figures 11, 12, and 13. Figure 11 results from plotting all points run at 15% excess air, Figure 12 from all points run at normal load and low excess air, and Figure 13 from all points run at normal load and 15% excess air. Figure 11 indicates a high dependence of coal and gas on air preheat (about 50 ppm NO increase per 100°F increase in preheat) with oil showing a smaller effect. However, if the percentage increase in NO is used instead of absolute change in ppm NO from 400 to 650°K (300 to 700°F) preheat, coal shows a 35% increase, oil 33%, and gas 71%. Figure 12, the curves for low excess air, shows a significant dependence on preheat for gas only. There is no effect for coal and oil. The change for gas is still about 50 ppm NO increase per 100°F of preheat increase. Figure 13 at normal load and 15% excess air shows about the same effects as Figure 11. A comparison of these three figures leads to the tentative conclusion that conversion of fuel-bound nitrogen increases with decreasing air preheat.

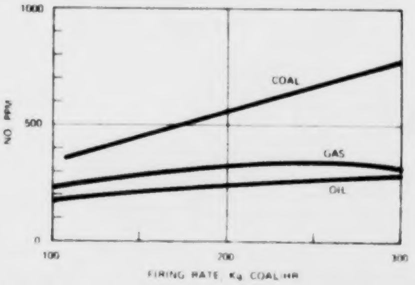

FIGURE 10. EFFECT OF FIRING RATE ON NO_x

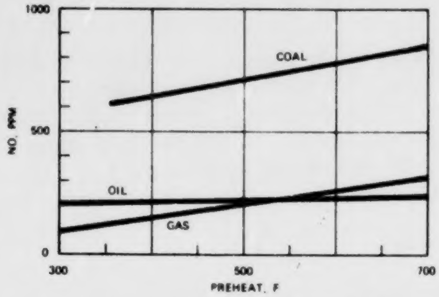

FIGURE 11. EFFECT OF PREHEAT ON NO_x (CONSTANT EXCESS AIR)

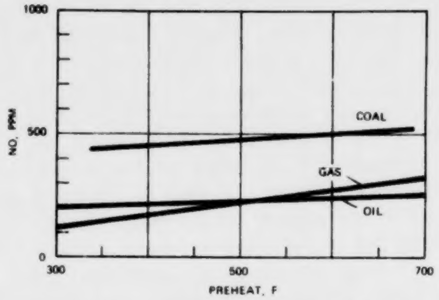

FIGURE 13. EFFECT OF PREHEAT ON NO_x (CONSTANT LOAD AT NORMAL EXCESS AIR)

D. Flue Gas Recirculation

The coal burner arrangement which has been used requires transport air for the coal which is defined as primary air (see Figure 14). The balance of the burner air is called secondary air. The primary air is about 15% of the total air under normal load and excess air. At low loads, the percentage of primary air increases to over 20%. The oil is steam atomized and, therefore, for both gas and oil, there is no primary air in the burner.

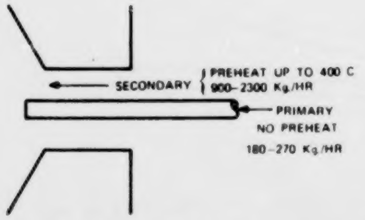

FIGURE 14. AIR INPUT FOR COAL COMBUSTION

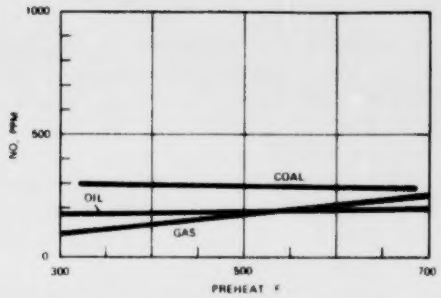

FIGURE 12. EFFECT OF PREHEAT ON NO_x (CONSTANT LOAD AT LOW EXCESS AIR)

Primary Flue Gas Recirculation (Coal Only)

Figure 15 shows the result of primary flue gas recirculation for coal combustion. The flue gas was substituted for air so that the total transport gas weight remained constant. The air displaced by the flue gas was added to the secondary air to maintain a constant air to fuel ratio. Since the primary air represents about 15% of the total air for combustion, a high level of flue gas substitution represents only a small amount of flue gas recirculation. Blending the flue gas with the primary air does tend to affect the primary ignition zone and hence burner performance. As a result, data obtained under these test conditions showed considerable scatter. However, it is felt that the trend shown in Figure 15 is probably realistic and that any reduction in NO by this approach is relatively insignificant.

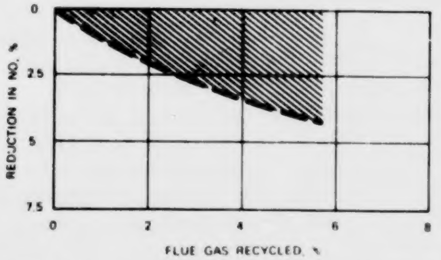

FIGURE 15. PRIMARY FLUE GAS RECIRCULATION (COAL ONLY)

Secondary Flue Gas Recirculation

Figure 16 shows the percentage of NO reduction versus the percentage of flue gas recycled. The flue gas was added to the secondary flow and the air to fuel ratio was held constant.

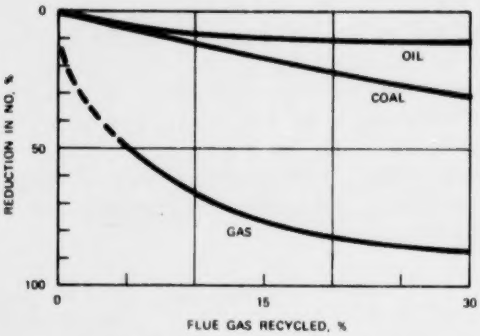

FIGURE 16. FLUE GAS RECIRCULATION

The curve for coal indicates for the application of 10% to 15% flue gas recirculation that a maximum reduction of only 10% to 15% can be expected in NO emission levels. The curve for gas shows a very great reduction in NO levels even with relatively low flue gas recirculation. The dotted portion of the line indicates that no tests have been run below 10% flue gas recirculation for gas and the curve is simply interpolated from the origin to the data available. The oil curve shows very little reduction of NO emissions with flue gas recirculation.

At present, it is felt that these data indicate flue gas recirculation is effective in reducing thermal fixation of NO but may increase the amount of NO formed from conversion of fuel-bound nitrogen.

E. Staged Combustion

As seen in Figure 17, there are two areas in a normal utility unit where second stage air can be added for final combustion. The air can be added in the burner area by running some burners rich and some lean, or by putting air only through separate burners, etc. Or, the air can be added at a distance away from the burner area. Our two sets of slots are spatially arranged to simulate either method of second stage air addition. The front slots simulate addition of air in the burner area, or very close to it, whereas the side slots simulate addition of the air further away from the burner area with rapid mixing for the second stage combustion.

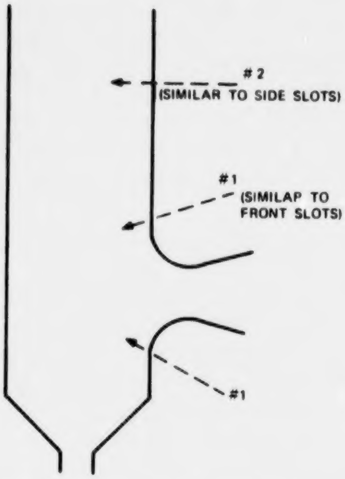

FIGURE 17. STAGED COMBUSTION OPTIONS

A comparison of results obtained with the two port locations is shown in Figure 18. At the higher burner to total air ratios results are similar. It should be noted that these data were obtained with fixed burner and slot openings. Thus as the burner to total air ratio decreases and staging increases, the air velocity through the ports increases and the burner velocity decreases. This effect on combustion performance is unsatisfactory at lower burner to total air ratios when using the side slots for staging. The curves do indicate that a 50% reduction in NO emission levels by staging is possible for coal firing.

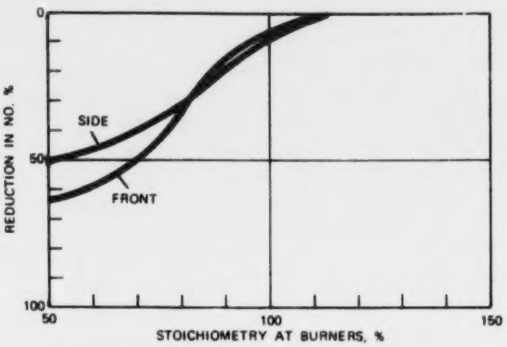

FIGURE 18. STAGED COMBUSTION FOR COAL PORT POSITION VARIABLE

Figures 19, 20, and 21 represent the results from observation of staged combustion for coal, oil, and gas, respectively. For coal and oil, flue gas recirculation showed no further reduction in NO when used in combination with staged combustion.

There are two curves for staged combustion with coal (Figure 19). The "S" shaped curve represents normal two-stage combustion for the front slot firing at 15% total excess air and normal load. The straighter line represents substoichiometric firing in which the second stage air was simply shut off and the overall air to fuel ratio is the same as the burner ratio in the first stage. The straight line intercept indicates that below 75% burner air to fuel ratio, no NO would be expected to appear in the first stage combustion. The two-stage combustion curve indicates that a minimum in the NO occurs at a burner air to fuel ratio of about 50%. This minimum is not unexpected because it represents the diminishing return on the reduction of conversion of the fuel-bound nitrogen in the first stage as contrasted to increasing thermal NO formation due to increased Btu content in the second stage. There are two major conclusions to be drawn from this information. First, there is a lower level of burner stoichiometry below which the NO formation in the first stage appears to drop to zero and it is of no further benefit to lower the air to fuel ratio at the burner.

Secondly, with the latent Btu content of the gas increasing rapidly in the residual gas to be burned in the second stage, the second stage flame temperature and therefore the thermal fixation of NO is expected to rise again. The position of maximum NO reduction is influenced by port position and heat removal rate as well as other factors such as air velocity and mixing rate. It is therefore certain that such a turnover in the NO reduction curve should and probably does exist.

The oil curve (Figure 20) is the same shape as the coal curve. The degree of reduction in NO levels for staging oil is less than coal because of the much lower base levels of NO.

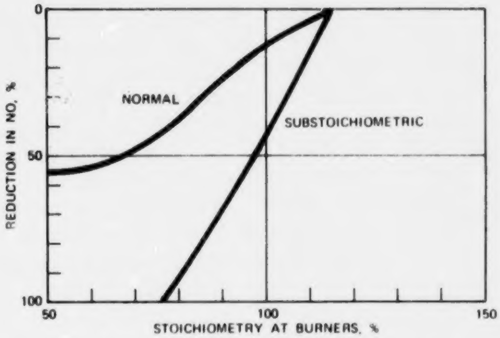

FIGURE 19. STAGED COMBUSTION (COAL)

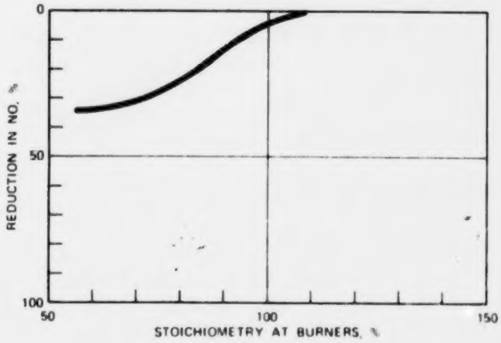

FIGURE 20. STAGED COMBUSTION (OIL)

For two-stage combustion of gas (Figure 21), the addition of flue gas recirculation becomes very important. The greater effect for the flue gas recirculation is found in the burner. This indicates that it prevents or reduces the formation of the precursors in the first stage which leads to thermal NO as well as preventing formation of NO in the second stage. If the only function of flue gas recirculation in a natural gas flame were temperature drop and initially lowered O_2 concentration, it would be just as effective in the second stage air as it is in the burner air since combustion taking place in the first stage is usually substoichiometric. An increase in velocity and mixing in the first stage is also expected when flue gas is added through the burner.

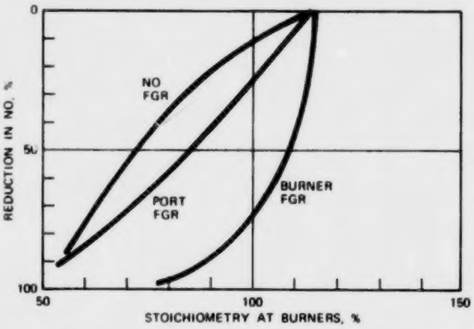

FIGURE 21. STAGED COMBUSTION (GAS)

F. Swirl (gas only) and Quench (coal only)

Decreasing the swirl with our burner, as shown in Figure 5, for coal firing led to combustion instability; hence this variable was not investigated for coal during this phase.

Only maximum swirl (30° vane setting) and no swirl (0° vane setting) tests were run for gas (Table 1). In general, the effect of increased velocity on mixing is shown. Higher load and higher excess air led to greater reductions in NO. The effect at low air regardless of load (the point at low load, low air was 10, the average of 13 and 6 although the value of 6 is thought to be the correct one) indicates that the O_2 concentration is never high enough to directly influence thermal NO formation, or in other words, the NO may be kinetically limited rather than diffusion limited.

TABLE 1. EFFECT OF SWIRL (GAS ONLY) NO REDUCTION, % (MAXIMUM TO NO SWIRL)

	LOW AIR	MID AIR	HIGH AIR
LOW LOAD	10	8	12
MID LOAD	—	18	18
HIGH LOAD	4	18	21

The change in quench in the basic combustion unit was made by removal of part of the refractory brick lining in the furnace. All tests except the quench tests were run with a 1-inch thick refractory brick lining on the inside of the furnace from the burner to half way down the furnace, or to a distance of 4 feet. For a change in heat removal rate for the quench test, half of the brick was stripped out so that it covered the interior from the burner down a 2-foot length of the furnace. The results of these tests are shown in Table 2. Although this alteration changed the quench rate, there is not enough information to make a quantitative calculation of the change. All conditions except low excess air showed about the same reduction in NO emission levels.

TABLE 2. EFFECT OF QUENCH ON COAL (PERCENT REDUCTION IN NO)

	LOW AIR	MID AIR	HIGH AIR
LOW LOAD	—	—	—
MID LOAD	0	20 (20 STAGED)	—
HIGH LOAD	—	20	20

VI. SUMMARY

The most effective means of controlling NO emissions from an operational point of view as found in the basic combustion unit would appear to be to control excess air, preheat, and load together since they are heavily interdependent (ref. Table 3). If load cannot be varied, control of the combination of lower preheat and excess air does not appear to be more effective than control of the excess air alone.

To date, pilot plant results indicate the concept of staged combustion or perhaps delayed mixing appears to be the most effective means of NO_x reduction. If this can be accomplished by progressive mixing in the individual burner zone, then operator acceptance seems assured. However, if effective control requires a wide physical separation of the two sources of air, there is a real concern that unacceptable slagging and corrosion problems may be encountered. Therefore, field testing of a unit under controlled conditions to establish the long term effect of operating in this manner would be required before universal acceptance can be assured.

TABLE 3. SUMMARY OF QUALITATIVE EVALUATION

INCREASING:	COAL	GAS	OIL
EXCESS AIR	+++	+	+
LOAD – LOW PREHEAT	++	0	+
– HIGH PREHEAT	0	+	++
PREHEAT – LOW AIR	0	++	0
– HIGH AIR	++	++	0
FLUE GAS RECIRCULATION	- -	- - - -	-
STAGED COMBUSTION	- - -	- - -	- -
– POSITION	+	0	0
– WITH FGR	0	- - - -	0
QUENCH (DECREASING)	+	ND	ND
SWIRL	ND	+	ND

PRELIMINARY EVALUATION OF COMBUSTION MODIFICATIONS FOR CONTROL OF POLLUTANT EMISSIONS FROM MULTI-BURNER COAL-FIRED COMBUSTION SYSTEMS

By

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The Bureau of Mines (through an interagency agreement with EPA) has extended a program to evaluate the effects of combustion modifications on control of emissions from multi-burner coal-fired systems. Experimentation was conducted in a 500 lb. per hour pulverized-coal fired unit whose operation closely simulates industrial practice. A photograph of the furnace is shown in figure 1. The unit is 12 ft. high, 7 ft. wide, and 5 ft. deep, with water cooled walls. Four burners are located on the front wall. A half section of the combustor is shown in figure 2. Combustion gases leave the furnace at about 2000° F, cool to about 1000° F in the convective heat transfer zone, then exchange heat with secondary air in the recuperative air heater. The effects of several operating techniques have been investigated---single stage combustion with reduced excess air, two stage combustion, bias-firing, and flue gas recirculation.

Coal feed rate was maintained at 500 lb per hour, fuel particle size at 75 percent through 200 mesh and secondary air temperature at 600° F in all tests. Except for the series of reduced excess air tests, excess air was maintained at 20 percent.

Variations in Excess Air

By decreasing the amount of excess air from the conventional levels of 20-25 percent, a substantial lowering of NO_x emissions can be achieved. As shown in figure 5, NO_x decreased from 1.45 gm/10^6 cal at 20 percent excess air, to .5 gm/10^6 cal at about 2 percent excess air. However, as shown in figure 4, this reduction in NO_x emission was accompanied by a decrease in carbon combustion efficiency.

Two-Stage Combustion

In two-stage combustion, the first stage was supplied with air ranging from 80 to 105 percent of stoichiometric. Sufficient air was introduced at the furnace outlet to produce 20 percent overall excess air. Figure 5 shows a plot of NO_x emissions as a function of air supply to the first stage. Nitrogen oxides emission decreased from about 1.1 gm $NO_2/10^6$ cal when 105 percent of stoichiometric air was supplied to the first stage to .77 gm $NO_2/10^6$ cal when 80 percent of stoichiometric air was supplied to the first stage. This reduction was accomplished while maintaining carbon combustion efficiency greater than 98 percent. Also shown in this figure are the results of bias-firing experiments. This is a variation of staged combustion, where stoichiometric air or less than stoichiometric is supplied to the lower burners, with sufficient air supplied to the upper burners to provide 20 percent excess air overall. It is evident that little reduction occurred when 105 percent of stoichiometric air was supplied to the lower burners. Some reduction did occur when 90 percent of stoichiometric air was supplied to the lower burners. It wasn't possible to reduce the air to the lower burners below

90 percent, because of the increased demand on the upper burners. A reduction to 80 percent of stoichiometric to the lower burners would require 160 percent of stoichiometric to the upper burners. Stable flames could not be maintained with air supplied in this amount. To further investigate the effect of two-stage combustion, the second stage air probe was relocated to a point nearer to the flame zone. A sketch of the probe location is shown in figure 6. With air introduced at this point, a survey was made of NO_x emissions when the probe was rotated through an angle of 180° from a point normal to the front wall to a point normal to the rear wall. Also shown are the NO_x values obtained when second stage air was introduced at the various angles. Most significant reduction occurred with air introduced normal to the front and rear walls. Highest NO_x values were obtained when air was introduced at an angle approximately 30° from normal to the front wall. At this point the second stage air penetrated the primary combustion zone, increasing the intensity of combustion. The flames were forced sown along the front sloping wall resulting in overheating of the lower furnace section. Since the coal feed rate was constant during the test, the oxygen values are an indication of carbon combustion efficiency. Although a relatively large change in NO_x emissions occurred as the angle of introduction of second stage air was varied, the oxygen values indicate that carbon combustion efficiency was relatively constant. Furnace outlet temperatures were 1750° F, 1920° F, and 1850° F when air was introduced at points 1, 2, and 7, respectively. When the second stage air was introduced at an angle of about 45° at the original probe location near the exit of the furnace, the NO_x value was about 300 ppm and the furnace outlet temperature was 1923° F.

Flue Gas Circulation to Secondary Air

Figure 7 shows the results of tests in which various amounts of flue gas were recycled to the furnace through the secondary air streams. Temperature of the recycled gas was about 300° F. The curve indicates that a significant reduction in NO_x emission occurs when flue gas is recycled to the furnace through the secondary air streams. Furnace outlet temperature decreased with recycle from 2000° F at zero recycle to 1890° F at 24 percent recycle. The curve appears to flatten out between 24 and 30 percent recycle. The 30 percent point and an intermediate point will be checked to further define the curve in this region. In addition, several tests are planned to determine the effect of flue gas recycle in the primary air stream.

In addition to monitoring O_2 and NO_x, the following components were also measured during the tests - NO_2, SO_2, CO, CO_2, hydrocarbons, particulate, and furnace outlet temperature. The NO_2 was monitored with a chemiluminescent analyzer; the NO_2 generally ranged from 3-7 percent of the NO_x value. An NDIR analyzer was also used to monitor NO.

The CO emissions, as measured with an NDIR analyzer, generally ranged from 30 to 60 ppm for the standard and other tests except those operated at low excess air levels. In the test operated at 5 percent excess air, the CO increased to 1,000 ppm, at 2 percent excess air the CO further increased to 5,000 ppm.

Total hydrocarbon emissions were monitored during the tests with a flame ionization analyzer. The analyzer indicated that ambient and combustion air contained about 2-3 ppm hydrocarbons. Flue gas concentrations were on the order of 0.5 to 0.8 ppm in tests conducted at 20 percent excess air levels. The hydrocarbon emissions increased at lower excess air levels to 2 to 5 ppm at 5 percent excess air.

The amount of slagging experienced at a given operating condition is difficult to ascertain because of the relatively short period of operation at a given test condition. As far as could be noted visually, the degree of slagging was minor, and no difference could be noted between tests.

After the flue gas recycle tests are completed, the survey of the effect of the point of introduction of second stage air will be completed to include rotation of the second stage air probe through the remaining two quadrants. Thereafter the combustion studies will be continued to include combinations of the various combustion modifications.

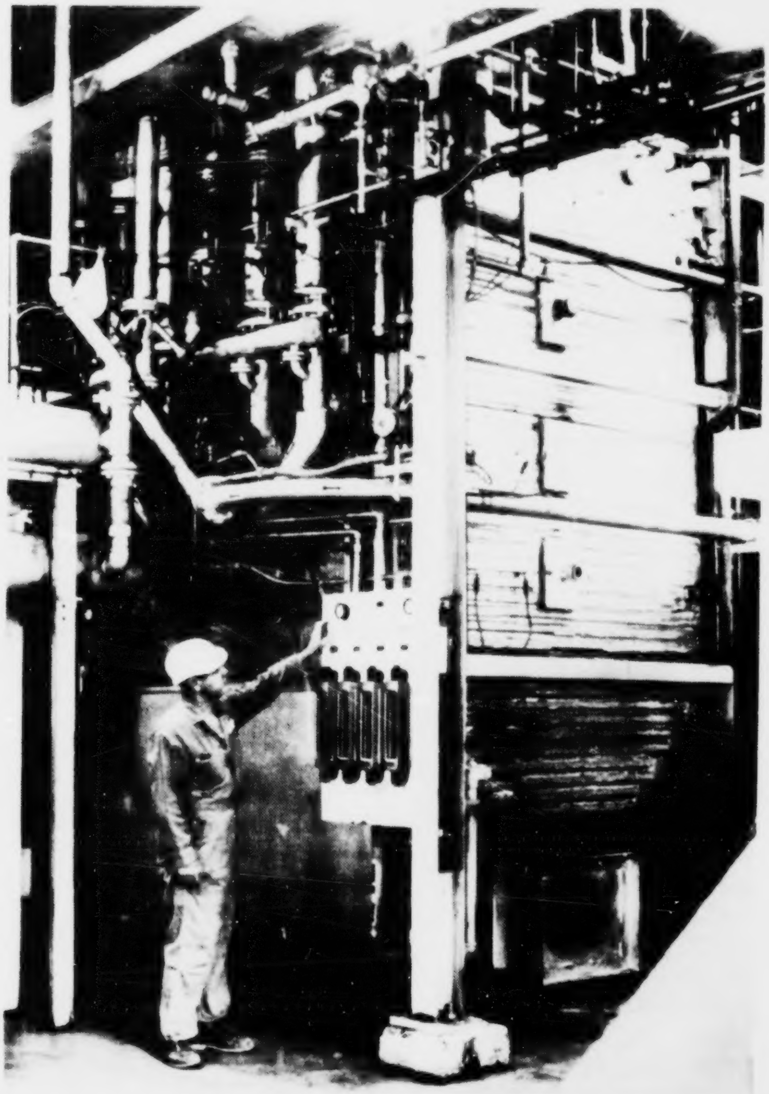


Figure 1. View of 500 lb/hr pulverized coal-fired combustor.

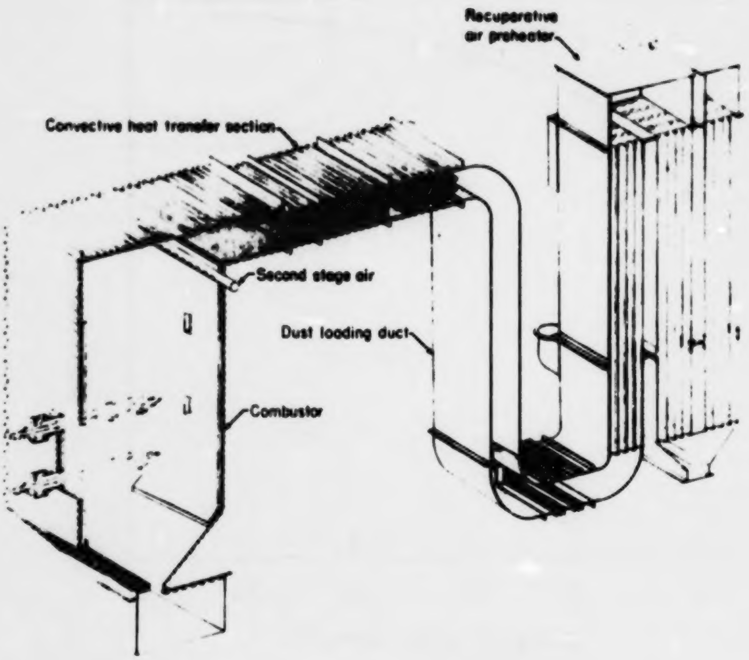

Recuperative air preheater
Convective heat transfer section
Second stage air
Dust loading duct
Combustor

Figure 2. 500 lb/hr coal combustor.

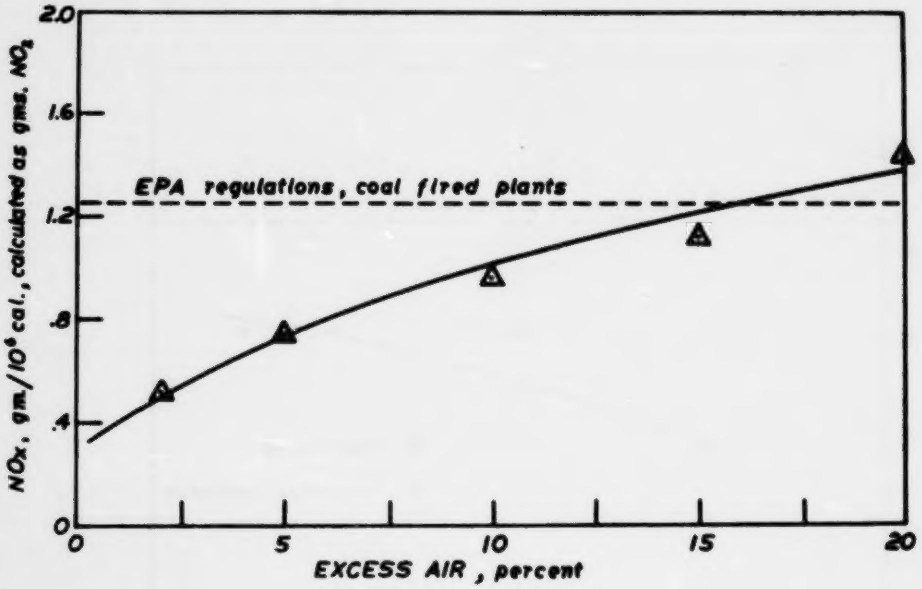


Figure 3. Nitric oxide formation as a function of excess air.

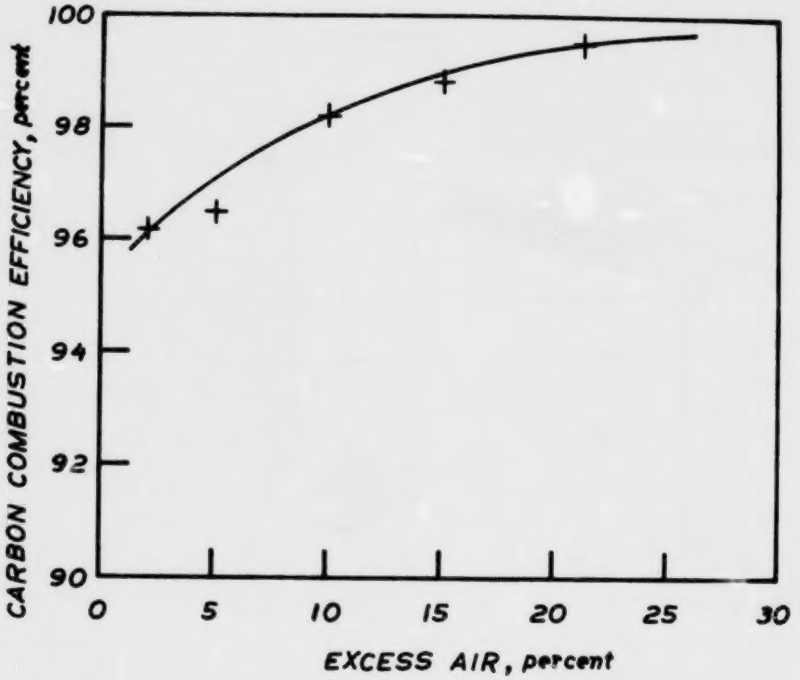


Figure 4. Carbon combustion efficiency as a function of excess air.

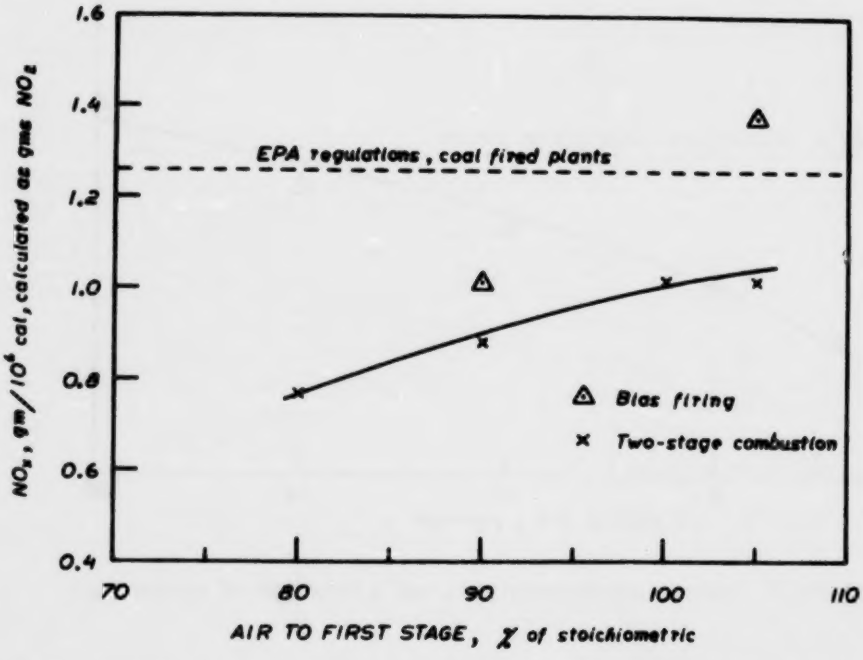
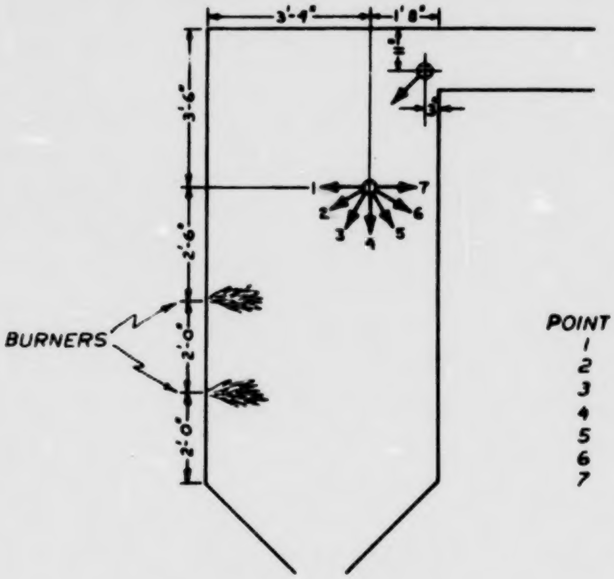


Figure 5. Nitric oxide formation with off-stoichiometric firing.


3'-4"
1'-8"
3'-6"
2'-6"
2'-0"
2'-0"
BURNERS
1
2
3
4
5
6
7

POINT	O_2, %	NO, ppm	NO_x, ppm
1	3.5	250	265
2	3.5	375	390
3	3.6	300	310
4	3.5	320	330
5	3.7	345	355
6	3.6	295	310
7	3.5	270	290

Figure 6. Effect of air injection angle upon NO_x emissions.

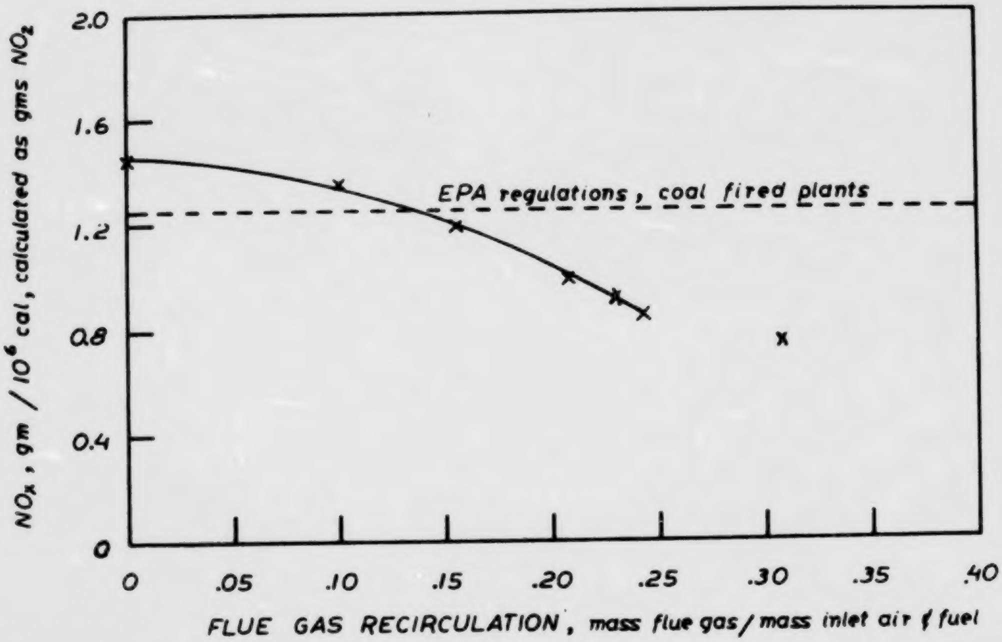


Figure 7. Flue gas recirculated to secondary air, percent.

NO_x EMISSION CONTROL FOR COAL-FIRED UTILITY BOILERS

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Control Systems Laboratory,
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SUMMARY

Esso Research and Engineering Company is conducting field studies on utility boilers under EPA sponsorship, to develop NO_x and other pollutant control technology, by modifying combustion operating conditions. In the current phase of continuing work on this problem, Esso's mobile sampling-analytical system has been used to test eight pulverized coal fired boilers of cooperating electric utilities. These boilers, including wall, tangentially, and turbo-furnace fired units, had been recommended by major utility boiler manufacturers as representative of their current design practices.

In addition to gaseous emission measurements, particulate emissions and accelerated furnace corrosion rates have been also determined in a number of cases. Esso's test design consisted of three phases. First, statistically designed short term runs were made, to define the optimum "low NO_x" conditions within the constraints imposed by boiler operability and safety, slagging, unburned combustible emissions and other undesirable side effects. Second, the boilers were usually operated for about two days under the "low NO_x" conditions defined in the first phase, to check operability on a sustained basis. Third, several boilers were operated under both baseline and "low NO_x" conditions for about 300 hours, with carbon steel corrosion coupons mounted on air-cooled probes exposed near the water walls of the furnaces, to obtain relative corrosion tendencies with accelerated rates.

Analysis of the gaseous emission data obtained shows that combustion operating modifications, chiefly low excess air firing, coupled with staged burner patterns, can reduce NO_x emissions from the coal fired boilers tested by 25 to 60%, depending on the unit and its flexibility for modifications. The NO_x emissions measured have been successfully correlated for both normal and modified firing conditions with the per cent stoichiometric air supplied to the burners.

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There are no major differences between particulate loadings under baseline and "low NO_x" operating conditions. However, unburned carbon in the fly-ash increases considerably with "low NO_x" firing for front wall and horizontally opposed fired boilers but, decreases substantially for tangentially fired units. The potential debits in overall performance based on these limited data for front wall and horizontally opposed fired boilers should be offset by improved efficiencies realized by lower excess air operation in "low NO_x" firing.

The accelerated corrosion tests have not revealed major differences in corrosion rates between normal and staged firing operations. More tests and long term runs, with particular emphasis on corrosion and slagging problems are needed to demonstrate the promising leads uncovered to date in this study.

1. INTRODUCTION

In continuing studies sponsored by EPA, Esso Research and Engineering Company (Esso) is involved in the development of nitrogen oxides (NO_x) emission control techniques for stationary sources. Our "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources" (1-3) characterized the nature and magnitude of the stationary NO_x emission problem, assessed existing and potential control technology based on technical feasibility and cost-effectiveness, developed a first-generation model of NO_x formation in combustion processes, and prepared a set of comprehensive 5-year R&D plan recommendations for the Government with priority rankings.

Fossil fuel fired electric utility boilers were identified by the above study as the largest single stationary NO_x emission sector, responsible for about 40% of all stationary NO_x. Consequently, as part of Phase II of our "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources", we conducted a systematic field study of NO_x control methods for utility boilers (4-6). The objectives of this field study were to determine new or improved NO_x emission factors according to fossil fuel type and boiler design type, and to explore the application of combustion modification techniques to control NO_x emissions from such installations.

Esso provided a specially designed mobile sampling-analytical van for the above field testing. Our van was equipped with gas sample, thermocouple and velocity probes, with associated sample treating equipment, and continuous monitoring instrumentation for measuring NO, NO_2, CO, CO_2, O_2, SO_2, and hydrocarbons.

Gas, oil, and coal fired utility boiler representative of the U.S. boiler population were tested, with gas, oil, and coal fuels, respectively. Combustion modifications were implemented in cooperation with utility owner-operators (and with major boiler manufacturer subcontractors for three of the coal fired boilers tested), and emission data were obtained in a statistically designed field program. The 17 boilers (25 boiler-fuel combinations) tested included wall-fired, tangentially-fired, cyclone-fired, and vertically-fired units ranging in size between 66 and 820 MW generating capacity.

Major combustion operating parameters investigated consisted of the variation of gross boiler load, excess air level, staged firing patterns, flue gas recirculation, burner tilt, primary/secondary air ratio, and air preheat temperature. Operation under reduced load conditions reduced the NO_x emissions, but only for gas firing was the percent NO_x reduction greater than the percent load reduction. Base-line emissions were correlated in a statistically significant manner with the MW generated per "equivalent" furnace firing wall. In general, unburned combustible emissions, i.e., CO and hydrocarbons were found to be negligibly small under base-line conditions, and acceptably low even with NO_x control combustion modifications. The NO_2 portion of the flue gas was always five percent or less of the total NO_x emitted.

The effectiveness of combustion modifications was found to vary with individual boiler characteristics for each fuel. For gas fired boilers, NO_x emissions could be reduced on the average by about 60% at full load, even though in large, gas fired boilers limited by heat transfer surface, NO_x emission levels as high as 1000 ppm prevailed in the absence of combustion modifications. Uncontrolled emissions from fuel-oil fired boilers averaged lower values than for gas firing, but combustion modifications could be less readily implemented. With coal firing, only two of the seven boilers tested (one a tangential unit, the other a front wall fired boiler) could be operated in a manner conducive to reducing NO_x emissions. This operation consisted of firing the operating burners in the lower burner rows or levels with substoichiometric quantities of air, and supplying the additional air required for the burn-out of combustibles (keeping overall excess air as low as possible) through the air registers of the uppermost row or level. In these short-term, exploratory tests, NO_x emissions were reduced by over 50%, compared with the standard firing mode, without decreasing thermal efficiency or increasing the amount of unburned carbon in the fly-ash. Due to deactivating the pulverizer mill to the top level of burners, the amount of fuel that could be fired was reduced, resulting in a decrease of about 15% from maximum rated capacity. The NO_x reductions achieved were not affected by these reductions in load, as normal and modified combustion operations were compared at the same boiler load.

While the exploratory data obtained in the above study on controlling NO_x and other pollutant emissions from utility boilers by combustion modifications showed good potential, a number of critical questions have remained to be answered. Thus, for coal fired utility boilers, problems of slagging, corrosion, flame instability and impingement, increased carbon in the fly-ash, the actual particulate loadings and potential decreases in boiler efficiency which may result from the modified combustion operations need to be assessed in sustained test runs.

The purpose of Esso's present field testing program, sponsored by EPA under Contract No. 68-02-0227, is to obtain the necessary data on the application of combustion modification techniques to coal fired utility boilers, in cooperation with boiler operators and manufacturers coordinated by EPA. Major U.S. utility boiler manufacturers (Babcock and Wilcox, Combustion Engineering, Foster Wheeler, and Riley-Stoker) have recommended boilers characteristic of their current design practices. They have provided their help in making arrangements for testing with the cooperating boiler owner/operators, and in a number of cases assigned representatives to participate in Esso's field tests.

In addition to the continuous monitoring instrumentation described above, four EPA-type particulate sampling trains have been added to Esso's system. These trains and other equipment are transported to the testing site in an auxiliary van.

The approach used for field testing coal-fired boilers is first, to define the optimum operating conditions for NO_x emission control in short-term, statistically design test programs, without apparent unfavorable side effects. Second, the boiler is operated for 1-3 days under the "low NO_x" determined during the optimization phase, for assessing boiler operability problems. Finally, where possible, sustained 300-hour runs are made under both baseline and modified combustion ("low NO_x") operating conditions. During this period, air-cooled carbon steel coupons are exposed on corrosion probes in the vicinity of furnace water tubes, to determine through accelerated corrosion tests whether operating the boiler under the reducing conditions associated with staged firing results in increased fire-side water tube corrosion rates. Particulate samples are obtained under both base-line and "low NO_x" conditions, and engineering information on boiler operability, e.g., on slagging problems, data boiler performance are also obtained.

So far, two front-wall, two horizontally opposed, three tangential, and one turbo-furnace coal fired boilers have been tested in the present study. The results obtained on these coal-fired boilers are discussed in this paper.

2. TEST PROGRAM APPROACH

This section of the present paper discusses the approaches used for representative boiler selection (in conjunction with EPA and utility boiler manufacturers); the various phases of the statistical test program designs; and the test methods employed. Methods of gaseous emission testing were quite similar to those used in Esso's "systematic field study" (4-6). In addition, particulate loadings of the flue gas stream, and the carbon content of the particulates were determined, and corrosion probing tests were conducted.

2.1 Test Program Design

This cooperative program of field testing utility boilers was conducted by Esso Research with the cooperation of utility boiler manufacturers and operators under the coordination of EPA. The proper selection of boilers representing current design practices for this program was the result of a cooperative planning effort. Esso Research developed a comprehensive list of selection criteria (see Appendix), to assist EPA and boiler manufacturers in preparing a list of potential boiler candidates. Each boiler manufacturer submitted a list of suggested boilers to EPA for review and screening. After consideration of such factors as design variables, operating flexibility, fuel type, geographic location and logistics, a tentative list of boilers was selected by EPA and Esso. Field meetings were then held at power stations to confirm the validity of the boilers selected and to obtain necessary boiler operating and design data.

The field meetings were attended by representatives of EPA, Esso Research, boiler manufacturers and utility boiler operating management. EPA described the background and need for the program and how it fits into the overall EPA program. Esso Research presented a broad summary of our previous findings, an outline of the three-phase program to be run at each boiler, and led the discussion aimed at developing the information necessary to construct a detailed program plan. These discussions produced an agreed upon list of combustion operating variables, the specific levels to be tested, estimated ease and length of time to change from one level to another, how the variables were interrelated, and what operating limitations or restrictions might be encountered. In addition, the proper number and specific location of sampling ports for gaseous, particulate, and corrosion probe insertion were also agreed upon. Tentative testing dates were scheduled with provision made for possible segregation of coal types, scheduling of pretest boiler inspection, calibration of measuring instruments and controls, scheduled maintenance, and other preparatory steps.

The up-to-date, comprehensive information obtained in these field meetings provided the necessary data for Esso to develop detailed, run-by-run test program plans for review by all interested parties. Each test program, tailored to take full advantage of the particular combustion control flexibility of each boiler, was comprised of three phases: (1) short test-period runs to determine NO_x emission reduction capability of the boiler; (2) a 1-3 day sustained "low NO_x" run to determine if slagging or other operating problems exist, and (3) 300-hour sustained "low NO_x" and normal operation runs, to determine quantitative measures of accelerated furnace side wall corrosion rates.

Statistical principles (as explained in more detail in our "Systematic Field Study" (4) provide paractical guidance in planning test programs, i.e., how many, and which test runs to conduct, as well as the proper order in which they should be run. These procedures allow valid conclusions to be drawn from analysis of data on only a small fraction of the total possible number of different test runs that could have been made. Table 1 will be used to illustrate briefly these principles applied to a front-wall fired boiler, TVA's Widows Creek Boiler No. 6. (Tangentially fired boilers present a more complex problem in experimental planning, since there are additional operating variables such as burner tilt, and secondary air register settings, that should be included in the experimental design. However, the same statistical principles apply.) There are four operating variables: (1) load, (2) excess air load, (3) secondary air register settings, and (4) burner firing pattern. Assuming three levels of each of the first three variables and eight different firing patterns available at each load, there are 216 different operating modes. However, only the 33 test runs shown, i.e., 15% of the potential maximum, provided the required information on this boiler to define practical "low NO_x" operating conditons.

Test run 10 operating conditions were chosen for the second phase of the experimental program, while test run 26 operating conditions are recommended for "low NO_x" operation under reduced load conditions. Test run 10 conditions can be selected with considerable confidence, since examination of the data indicates that each of the S_3 firing pattern runs produced lower NO_x levels than the corresponding S_2 firing pattern. The effects of day-to-day variables, such as coal type variability, etc. not under study were balanced between the two firing patterns, since runs 5, 6, 7 and 8 were run on one day, and 9, 10, 11 and 12 were run on another day. It should also be noted that each day's runs completed a one-half replicate of the complete factorial accomplished by two days of testing. Thus, the main effects of each factor and interactions between factors can be estimated independently of each other, with maximum precision. Repeat test runs under test run 10 conditions, during a two-day sustained period, were used to validate these results and to obtain an independent estimate of experimental error.

The same principles were applied to planning the 16 runs (13 through 28). Four test runs were completed each day, one run on each of the four staged firing patterns, and one run on each of the four excess air and secondary air register setting combinations. Thus, the conclusion that the S_4 firing pattern is the best of those tested rests on the combined results of 16 runs over a total of four days, and is generally true over all excess air and secondary air register settings. Note also that during staged firing, low excess air with secondary air registers set at 20% open, always gave the lowest NO_x levels over each of the four days of testing at 110 MW, and also, over the two days of testing at 125 MW. Because of the consistency of results such as these, the number of test runs required on similar type boilers tested later could be substantially reduced by judicious selection of run conditions for validation purposes.

Table 2 contains a summary of the eight coal fired boilers tested to date. Four are wall fired (two front-wall and two horizontally opposed); three are tangentially fired; and one is turbo-furnace fired. Boilers 1, 3 and 4 are Babcock and Wilcox units, boilers 5, 6 and 7 are Combustion Engineering boilers, while Crist No. 6 is a Foster Wheeler boiler, and Big Bend No. 2 was designed and constructed by Riley-Stoker. Full load ratings, the number of burners, and number of burner levels are shown for each boiler in Table 2, as well as the number of combustion operating test variables, and the number of test runs completed on each of these boilers.

TABLE 1

TEST PROGRAM DESIGN FOR WIDOWS CREEK NO. 6 UNIT

(Run No., Average % O_2 and Average ppm NO_x Emissions (0% O_2, Dry))

	L_1 - Full Load (125 MW)				L_2 - Reduced Load (110 MW)			
	A_1 - Normal Air		A_2 - Low Air		A_1 - Normal Air		A_2 - Low Air	
2nd Air / Firing Pattern	20% Open	60% Open	20% Open	60% Open	20% Open	60% Open	20% Open	60% Open
S_1 - 16 Coal 0 Air Only	(3) 2.8% 706	(1) 3.2% 693	(4) 1.9% 581	(2) 2.0% 593	(31) 4.9% 794	(29) 4.8% 734	(32) 2.8% 541	(30) 2.7% 525
S_2 - 14 Coal D_1 D_4 Air	(11) 3.8% 724	(5) 4.0% 639	(6) 2.0% 451	(12) 1.5% 498				
S_3 - 14 Coal A_1 A_4 Air	(7) 4.5% 645	(9) 4.1% 622	(10)* 1.7% 397	(8) 2.7% 458				
S_4 - 12 Coal A_1 A_2 A_3 A_4					(24) 4.5% 465	(13) 4.5% 537	(26)** 2.7% 346	(20) 3.0% 402
S_5 - 12 Coal A_1 A_4 B_2 B_3					(27) 4.9% 579	(17) 4.4% 560	(22) 3.4% 357	(14) 2.6% 399
S_6 - 12 Coal A_1 A_4 B_1 B_4					(15) 5.2% 549	(21) 6.1% 641	(19) 3.1% 351	(28) 4.5% 511
S_7 - 12 Coal A_1 A_4 D_1 D_4					(18) 4.3% 488	(25) 4.5% 577	(16) 3.0% 384	(23) 3.9% 511
S_8 - 12 Coal B_1 B_2 B_3 B_4								(20A) 2.2% 454

* "Low NO_x" condition selected for sustained run.

** "Low NOx" condition with further load reduction.

Pulverizer	Burner No.			
	1	2	3	4
A - Top Row	0	0	0	0
B - 2nd Row	0	0	0	0
C - 3rd Row	0	0	0	0
D - Bot. Row	0	0	0	0

TABLE 2

SUMMARY OF COAL FIRED BOILERS TESTED

STATION AND BOILER NO.	TYPE OF FIRING	FULL LOAD (MW)	NO. OF BURNERS	NO. OF LEVELS	TEST VARIABLES	NO. OF RUNS
1. WIDOWS CREEK 6	FRONT WALL*	125	16	4	4	43
2. CRIST 6	FRONT WALL	320	16	4	4	22
3. HARLLEE BRANCH 3	HOR. OPPOSED	480	40	4	4	45
4. FOUR CORNERS 4	HOR. OPPOSED*	800	54	6	5	26
5. NAUGHTON 3	TANGENTIAL	330	20	5	6	26
6. BARRY 4	TANGENTIAL	350	20	5	7	35
7. BARRY 3	TANGENTIAL**	250	48	6	4	8
8. BIG BEND 2	TURBO	350	24	1	4	14
						219

* FURNACE DIVISION WALL

** TWIN FURNACE

2.2 Test Methods

In this section the gaseous and particulate sampling and analytical methods are described. Furnace corrosion probing techniques and equipment used are also discussed.

2.2.1 Gaseous Sampling and Analysis

The objective of obtaining reliable gaseous emission data in field testing boilers requires a sophisticated sampling system. The sampling and analytical system used in this program has already been described in detail in the Esso Research and Engineering Company Report, "Systematic Field Study of NO_x Emission Control Methods for Utility Boilers" (4).

For the present study, further capabilities were added to the analytical instrument train by installing a Thermo-Electron chemiluminescent analyzer to provide measurements of NO and NO_x in addition to those obtained with the Beckman NO and NO_2 spectroscopic monitors. Figure 1 is a schematic diagram of the present configuration of Esso's sampling and analytical system.

Since samples are taken from zones of "equal areas" in the flue gas ducts, gas sampling probes are "tailor-made" for each individual boiler tested. Three stainless steel sampling tubes (short, medium, and long) are fabricated on the job site, and installed in quick-disconnect mounting probe assemblies, along with a thermocouple located at the mid-point of the duct for gas temperature measurement. At least two probes of this type are installed in each flue gas duct, or a minimum of four are used when there is only one large flue duct on the boiler. Thus, a minimum of 6 sample points per duct, or 12 per boiler are provided, thus assuring representative gas samples. All connections between the Esso Analytical Van and the probes are of the quick-disconnect type for ease of assembly and assurance of leak-proof joints.

In running field tests, the gas samples are withdrawn from the boiler under vacuum through the stainless steel probes to heated paper filters where the particulate matter is removed. These paper filters are maintained at 300-500°F. The gases then pass through rotameters, which are followed by a packed glass wool column for SO_3 removal. Initially, gas temperatures are kept as high as possible to minimize condensation in the particulate filters. After leaving the packed column at 250-300°F, the gas samples pass at temperatures above the dew-point through heated Teflon lines to the vacuum/pressure pumps. The sample is then refrigerated to a 35°F dew-point before being sent to the van for analysis. Usually, the van is located 100 to 200 feet from this point and the gas stream flows through Teflon lines throughout this distance.

As in our previous studies (4-6), our analytical van was equipped with Beckman non-dispersive infrared analyzers to measure NO, CO, CO_2 and SO_2, a non-dispersive ultraviolet analyzer for NO_2 measurement, a polarographic O_2 analyzer and a flame ionization detector for hydrocarbon analysis. The Thermo-Electron chemiluminescent instrument, as indicated above, was added to provide improved capabilities for NO and NO_x measurements. The measuring ranges of these continuous monitors are listed in Table 3.

FIGURE 1

ESSO RESEARCH TRANSPORTABLE SAMPLING
AND ANALYTICAL SYSTEM

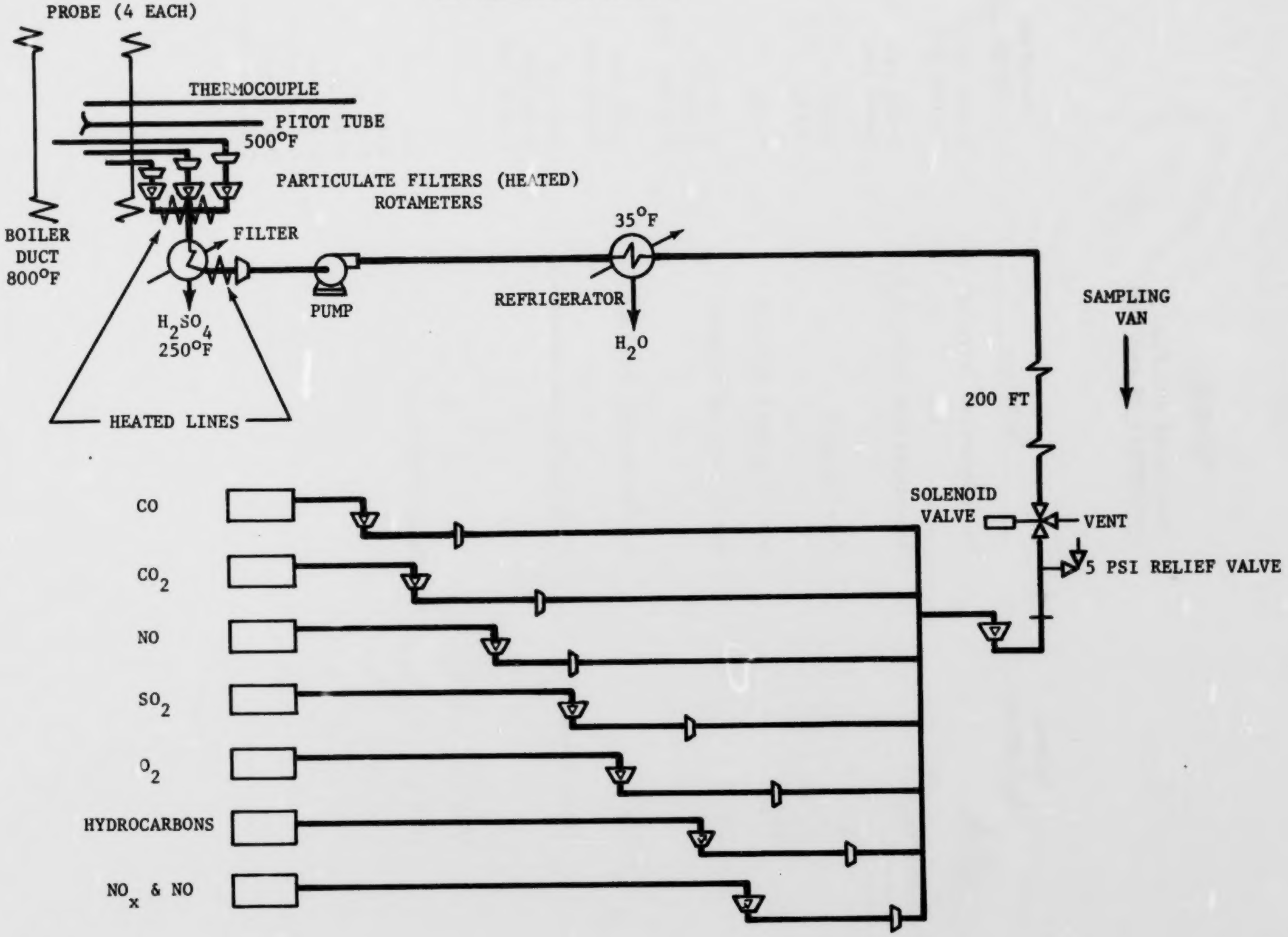

PROBE (4 EACH)
THERMOCOUPLE
PITOT TUBE
500°F
PARTICULATE FILTERS (HEATED)
ROTAMETERS
BOILER
DUCT
800°F
FILTER
H_2SO_4
250°F
HEATED LINES
PUMP
35°F
REFRIGERATOR
H_2O
SAMPLING
VAN
200 FT
SOLENOID
VALVE
VENT
5 PSI RELIEF VALVE
CO
CO_2
NO
SO_2
O_2
HYDROCARBONS
NO_x & NO

TABLE 3

CONTINUOUS ANALYTICAL INSTRUMENTS IN ESSO VAN

Beckman Instruments	Technique	Measuring Range
NO	Non-dispersive Infrared	0-400 ppm 0-2000 ppm
NO_2	Non-dispersive ultraviolet	0-100 ppm 0-400 ppm
O_2	Polarographic	0-5% 0-25%
CO_2	Non-dispersive infrared	0-20%
CO	Non-dispersive infrared	0-200 ppm 0-1000 ppm 0-23,600 ppm
SO_2	Non-dispersive infrared	0-600 ppm 0-3000 ppm
Hydrocarbons	Flame ionization detection	0-10 ppm 0-100 ppm 0-1000 ppm
Thermo Electron		
NO/NO_x	Chemiluminescent	0-2.5 ppm 0-10.0 ppm 0-25 ppm 0-100 ppm 0-250 ppm 0-1000 ppm 0-2500 ppm 0-10,000 ppm

A complete range of calibration gas cylinders in appropriate concentrations with N_2 carrier gas for each analyzer are installed in the system. Instruments are calibrated daily before each test, and in-between tests, if necessary, assuring reliable, accurate analyses.

Boiler flue gas samples are pumped continuously to the analytical van through four composite probes. While one sample is being analyzed, the other three are being vented. Switching to a new sample requires only the flushing of a very short section of sample line before reliable readings may be obtained. Four duplicate sets of analyses from each probe can be obtained in less than 32 minutes, thus speeding up the task of obtaining reliable gaseous emissions, and/or avoiding the need to hold the boiler too long at steady state conditions.

The validity of using the Thermo-Electron chemiluminescent NO/NO_x analyzer as the primary NO_x monitoring instrument was checked during the first series of tests conducted in this program, on TVA's Widows Creek Boiler No. 6. As shown in Figure 2, the NO_x data measured with the chemiluminescent analyzer were correlated with the sum of NO plus NO_2 data measured with the Beckman non-dispersive infrared NO and non-dispersive ultraviolet NO_2 instruments. As seen from the regression in Figure 2, excellent agreement was obtained between the chemiluminescent and spectroscopic instrumental methods. Thus, the chemiluminescent monitor was validated against the spectroscopic instruments, which in turn had been validated against a variety of other techniques, including the wet chemical phenoldisulfonic acid method, in previous Esso field studies (4-6).

Our instrumental measurement technique for flue gas O_2 and CO_2 determinations were checked by comparing the measured O_2 vs. CO_2 relationship to that calculated from fuel analysis, firing rate, and known excess air level. In our previous studies (4-6) we validated the instrumental O_2 and CO_2 measurements against Orsat analyses of grab samples.

The comparison of measured to calculated O_2 vs. CO_2 relationships is shown in Figure 3, based on data obtained in testing TVA's Widows Creek No. 6 Boiler.

As can be seen from Figure 3, the agreement between the regressions based on measurements and calculations is very good over the range of actual measurements.

2.2.2 Particulate Sampling

Modifications in the combustion process to minimize NO_x emissions tend to result in slower, less intense combustion conditions. Lowering excess air increases flame temperature which aids combustion, but limits the amount of oxygen available for the combustion process, directionally increasing the probability of burnout problems. Similarly, staging of burners, where some burners are operated at sub-stoichiometric conditions, and the remaining burners (or ports) are used as "air-ports" to complete combustion of the fuel, drastically limits available oxygen in the initial combustion phase, lengthens out flames and, with the slower, less intimate mixing of air and fuel, potentially increases unburned combustibles. Therefore, it was necessary to consider that combustion modifications implemented to minimize NO_x emissions could potentially increase particulate emissions from pulverized coal-fired boilers.

FIGURE 2

NO_x REGRESSION - BECKMAN NO + NO_2 VS CHEMILUMINESCENCE NO_x MEASUREMENTS

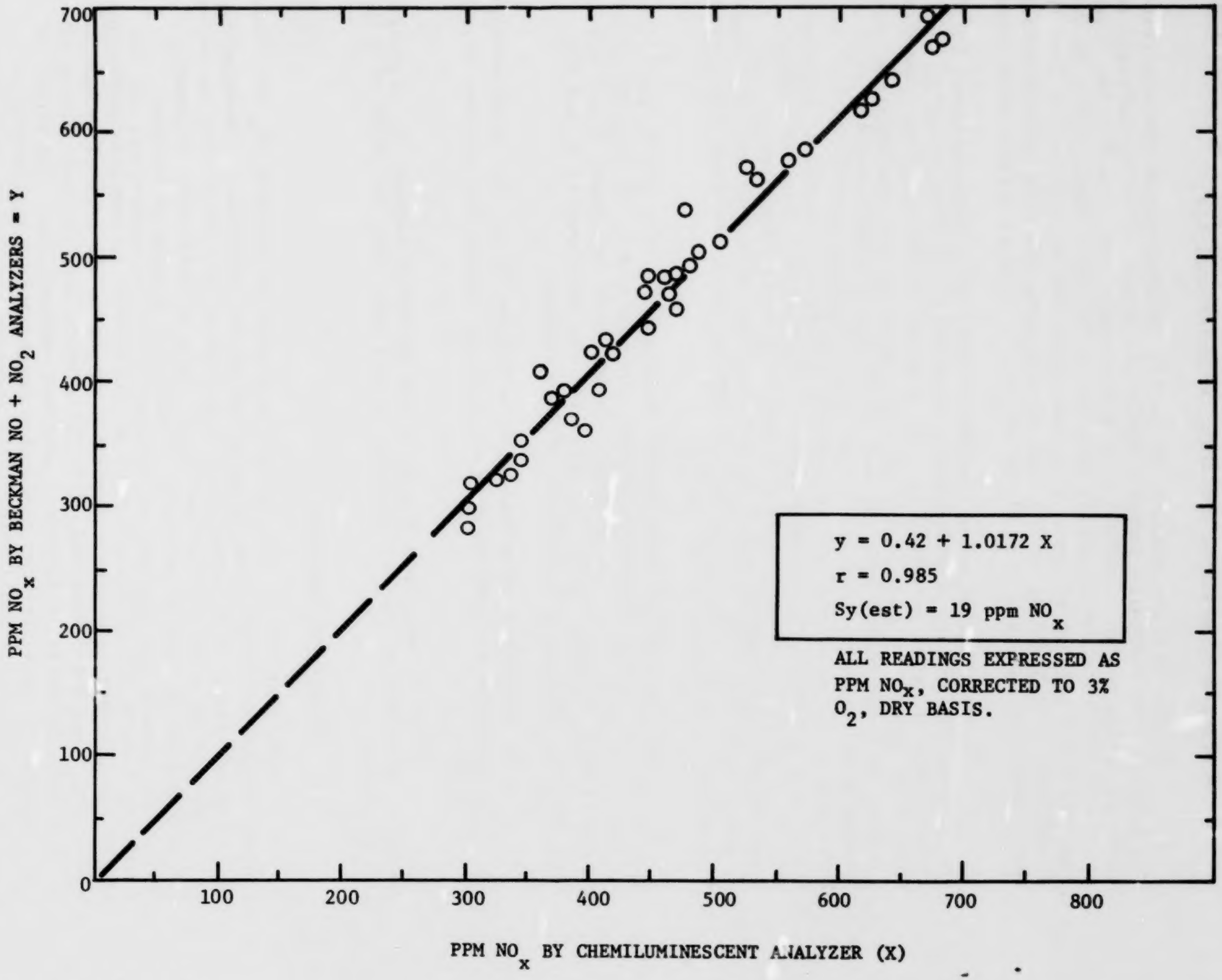
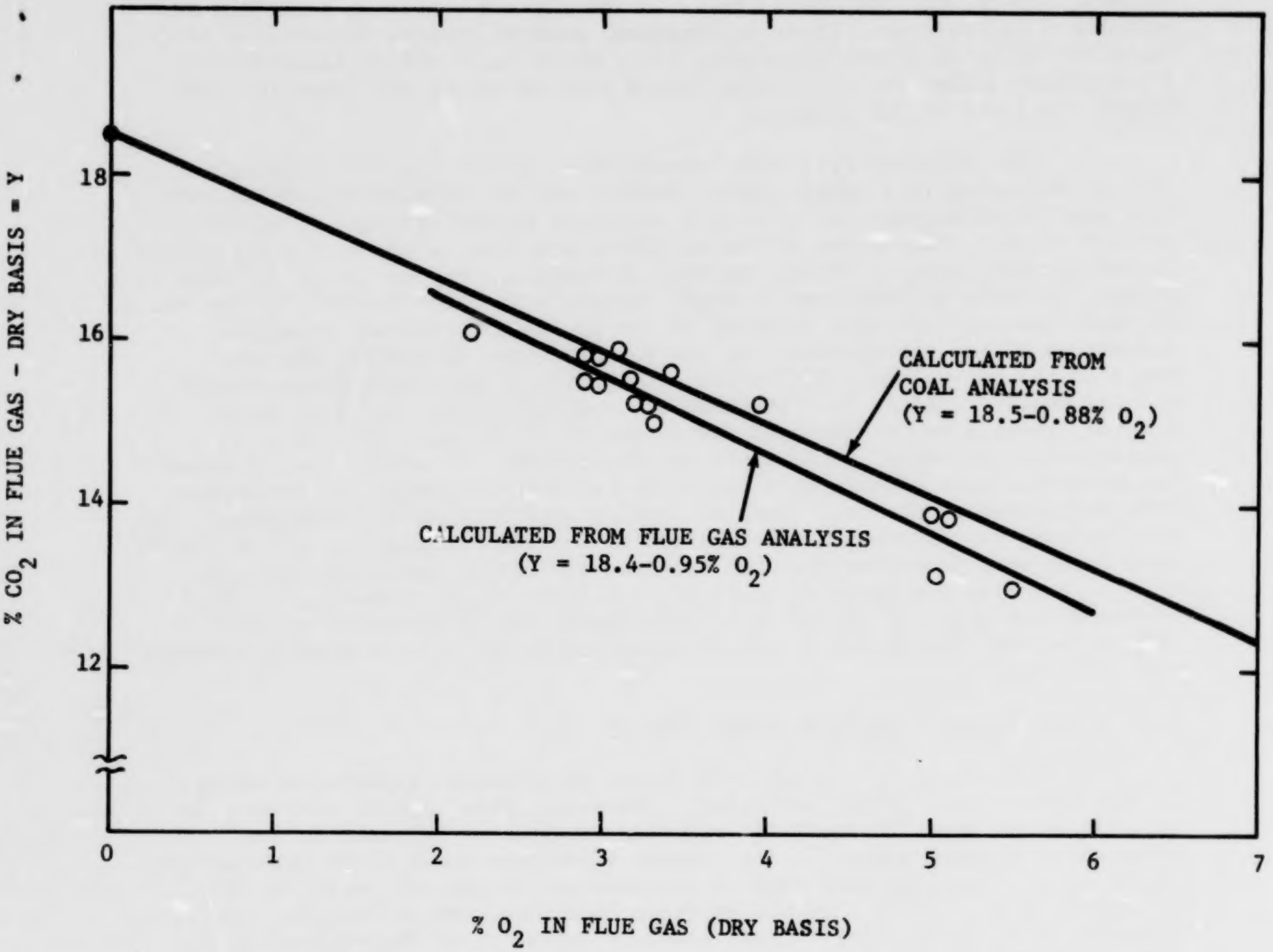


FIGURE 3

RELATIONSHIP BETWEEN % CO_2 AND % O_2 FLUE GAS MEASUREMENTS

(WIDOWS CREEK BOILER NO. 6 - RUN 1B)



In view of the above, an important phase of our field test program on coal fired boilers was directed at particulate emissions. The objective of this effort was to obtain sufficient dust loading information to determine the potential adverse side effects of "low NO_x" combustion modifications on particulate emissions, with respect to total quantities and per cent unburned carbon, vs. similar data obtained under normal or baseline operating conditions. Specifically, such data are needed to evaluate the changes, if any, that might occur in total dry filterable solids passing through the boilers, and on unburned combustibles in the fly-ash resulting from "low NO_x" emission modifications. Other information, such as changes in particle size distribution or in electrical conductivity which could affect electrostatic precipitator collection efficiency, would also be of interest, but this was beyond the scope of our program.

Four Research Appliance Company EPA-type particulate sampling trains, including four sample boxes, probes, and two isokinetic pumping sets were used in obtaining dust loading data on six pulverized coal fired utility boilers to date. The names of the utilities and details of the boilers tested, including size, type of firing, numbers of burners, etc. are given in Table 2. Except for tests at Utah Power & Light Company's Naughton Station, Boiler No. 3, all dust loading data were obtained in the flues at convenient locations downstream of the air-heaters. At the Naughton Station testing was done ahead of the air-heaters, due to inaccessibility of locations downstream of the air heaters. Also, on Alabama Power Company's Boiler No. 4 at Barry Station, testing was carried out downstream of the precipitator (with the precipitator shut-off), immediately before entering the stack. In all cases two traverses were made in each flue with one probe assembly, in accordance with prescribed procedures. However, strict adherence to EPA-recommended test methods was not always possible due to the limited availability of sample port locations, interferences with building and boiler appurtenances, and the limited time and manpower available for these tests. However, it should be remembered that the objective of these tests was to determine relative changes between normal and modified firing operations, not to measure accurate dust loadings.

2.2.3 Furnace Corrosion Probe Testing

Pulverized coal fired boilers do, on occasion, experience wastage of the furnace wall tubes (corrosion). Normally, this type of corrosion is experienced in areas of localized reducing atmospheres adjacent to the midpoint of furnace sidewalls near burner elevations where flame impingement could occur. Remedies have been to increase the excess air level so that an oxidizing atmosphere prevails at these locations, and to increase the fineness of pulverization, so that complete oxidation of the pyrites in the coal is accomplished before these species have a chance to reach the furnace wall tubes. For new boilers, another remedy has been to increase distances between the burners and the sidewalls, to minimize potential impingement. Several mechanisms have been postulated for this type of corrosion which appears to be associated with the formation of pyrosulfates from the coal ash (at 600-900°F) and iron sulfide, or SO_3 from the pyrites.

Combustion modifications for NO_x emission control are generally most effective at low excess air or substoichiometric air conditions in the flame zone, i.e., at conditions that may contribute to furnace tube wall corrosion. Our prior field tests of coal-fired boilers have been of short duration, allowing no time to assess such side-effects. However, it has been recognized that the effects of modified firing operations on furnace tube wall corrosion need to be evaluated (4-6). Discussions with boiler manufacturers and operators indicated that this potential problem was one of their greatest concerns. It was also evident that acclerated corrosion probe tests would be necessary to establish that "low NO_x" operation with coal could be carried out, since there was a general unwillingness to operate on a long-term basis using the boiler as a test medium.

Accordingly, one of the important aspects of our field test program was to design and construct controllable corrosion probes, and to define the extent of the potential corrosion problem. The objective of our furnace corrosion probing runs was to obtain "measurable" corrosion data on potential side effects of "low NO_x" firing conditions on furnace wall tubes. We received excellent advice and help in evaluating the problem and defining our approach to corrosion studies by Combustion Engineering Company research representatives, and by Esso's corrosion experts.

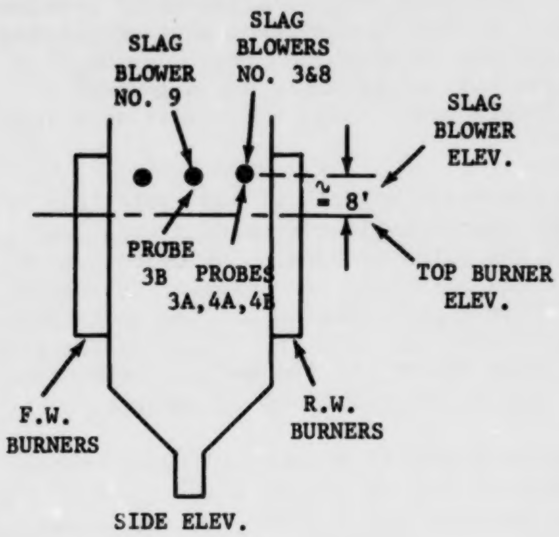
Our approach to obtaining data was to expose corrosion probes inserted into available openings located at the "vulnerable" areas of the furnace (see Figure 4), under both baseline and "low NO_x" firing conditions. Based on prior corrosion testing, it was concluded that exposure for approximately 300 hours at elevated coupon metal temperatures (above normal furnace tube metal temperatures) to accelerate corrosion, would produce "measurable" corrosion on SA-192 carbon steel (furnace tube type) coupon material. Since our objective was to show relative differences in corrosion, if any, between baseline and "low NO_x" firing, exposure temperatures at both conditions were set at approximately 875°F; i.e., high enough to accelerate corrosion, and just below the 900°F limit above which pyrosulfates apparently are not formed.

Figure 5 and 6 show details of the corrosion probes, based on Combustion Engineering's design. Essentially, this design consists of a "pipe within a pipe", where the cooling air (plant air supply) is admitted to the ring-coupons exposed to furnace atmospheres at one end of the probe through a ½-inch stainless steel tube roughly centered inside of the coupons. The amount of cooling air is automatically controlled to maintain the desired set-point temperature (875°F) on the coupons. The cooling air supply tube is axially adjustable with respect to the corrosion coupons, so that temperatures of both coupons may be balanced. To simplify the presentation, thermocouples installed in each coupon are not shown in Figures 5 and 6. Normally, one thermocouple is used for control, and the other one for recording. The cooling air travels backwards along the 2½-inch extension pipe and discharge outside of the furnace. Thus, there is no interference with the cooling air and the furnace atmosphere at the coupon location.

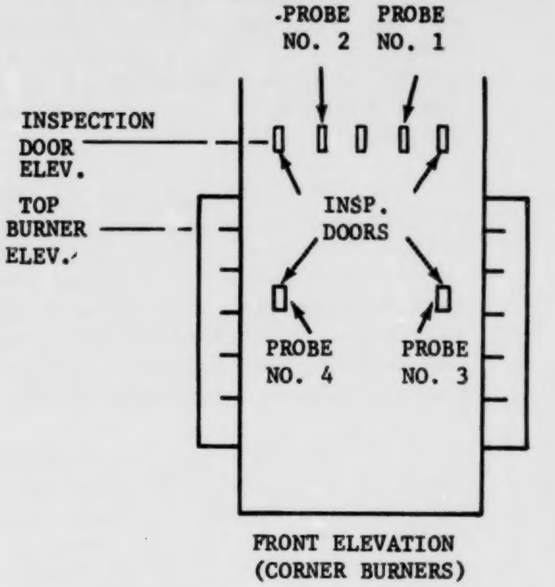
FIGURE 4

FURNACE CORROSION PROBE LOCATIONS

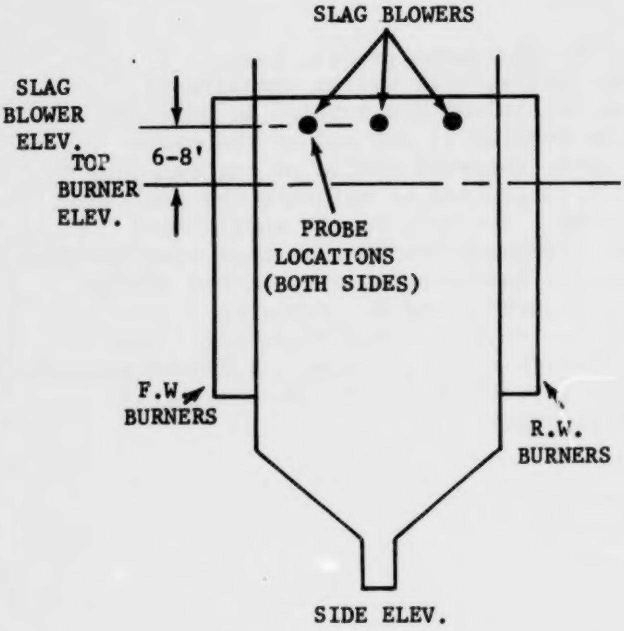
GEORGIA POWER
HARLLEE BRANCH STATION
BOILERS NO. 3&4


SLAG BLOWER NO. 9
SLAG BLOWERS NO. 3&8
SLAG BLOWER ELEV.
≃ 8'
PROBE 3B
PROBES 3A,4A,4B
TOP BURNER ELEV.
F.W. BURNERS
R.W. BURNERS
SIDE ELEV.

UTAH POWER AND LIGHT COMPANY
NAUGHTON STATION - BOILER NO. 3


PROBE NO. 2
PROBE NO. 1
INSPECTION DOOR ELEV.
TOP BURNER ELEV.
INSP. DOORS
PROBE NO. 4
PROBE NO. 3
FRONT ELEVATION (CORNER BURNERS)

ARIZONA PUBLIC SERVICE COMPANY
FOUR CORNERS STATION - BLRS. NO. 4&5


SLAG BLOWERS
SLAG BLOWER ELEV.
6-8'
TOP BURNER ELEV.
PROBE LOCATIONS (BOTH SIDES)
F.W BURNERS
R.W. BURNERS
SIDE ELEV.

ALABAMA POWER COMPANY
BARRY STATION - BOILER NO. 4

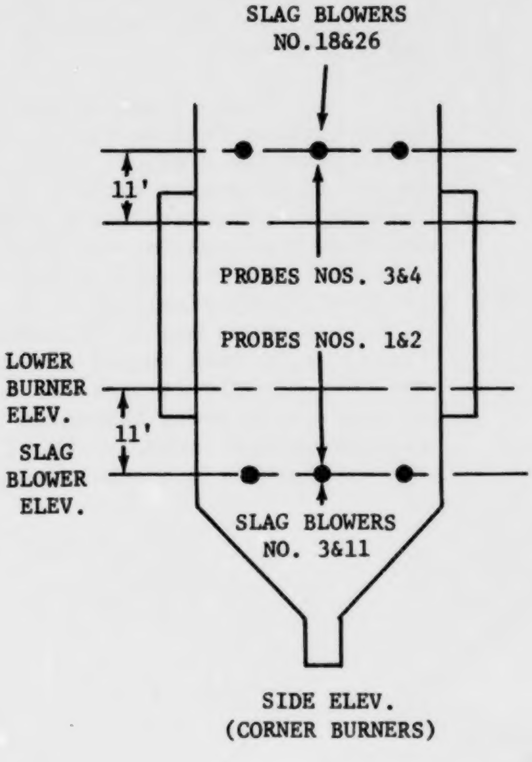

SLAG BLOWERS NO.18&26
11'
PROBES NOS. 3&4
PROBES NOS. 1&2
LOWER BURNER ELEV.
11'
SLAG BLOWER ELEV.
SLAG BLOWERS NO. 3&11
SIDE ELEV. (CORNER BURNERS)

FIGURE 5

CORROSION PROBE
DETAIL OF 2½" IPS EXTENSION PIPE AND END PLATE
(OUTSIDE OF BOILER)

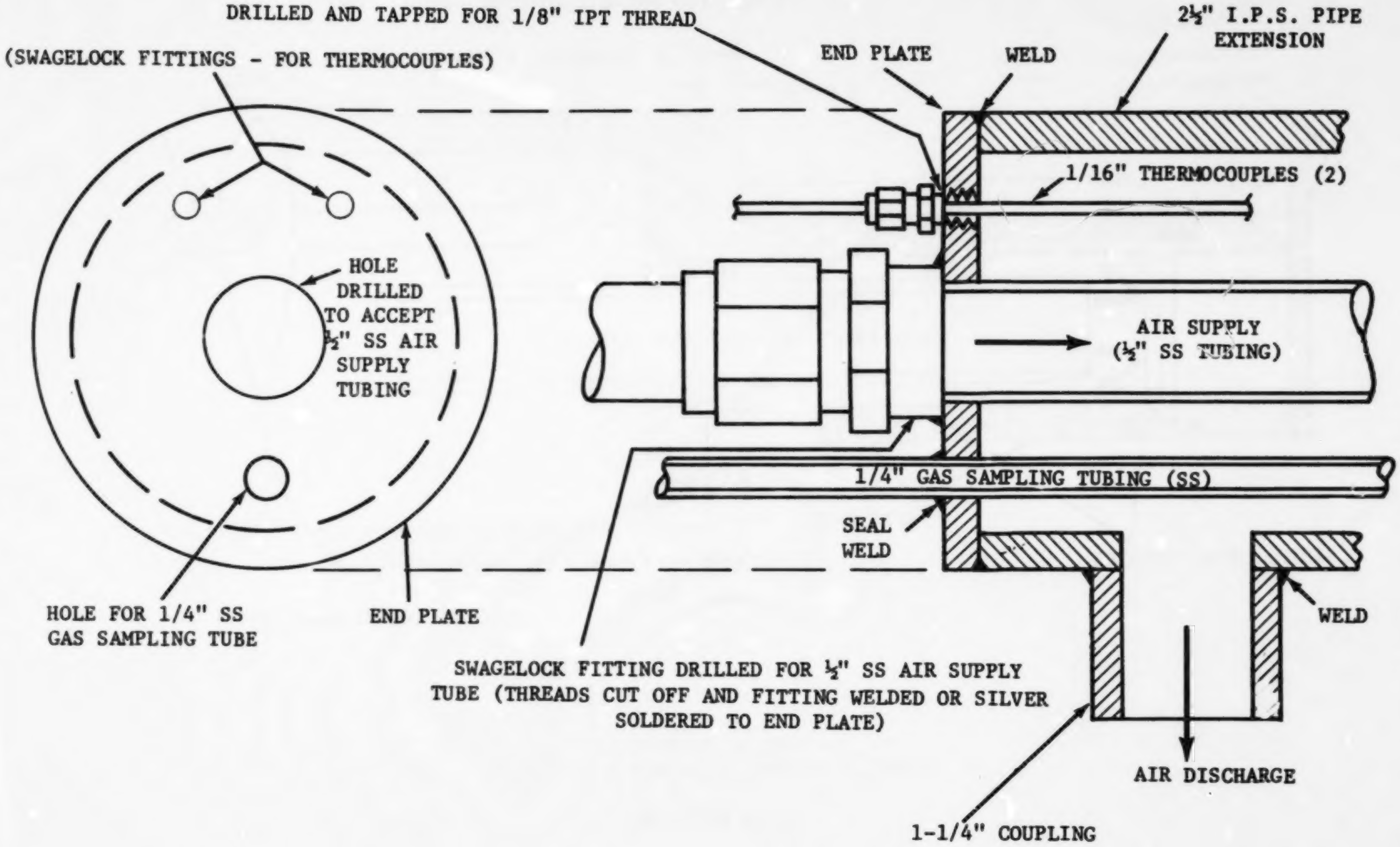
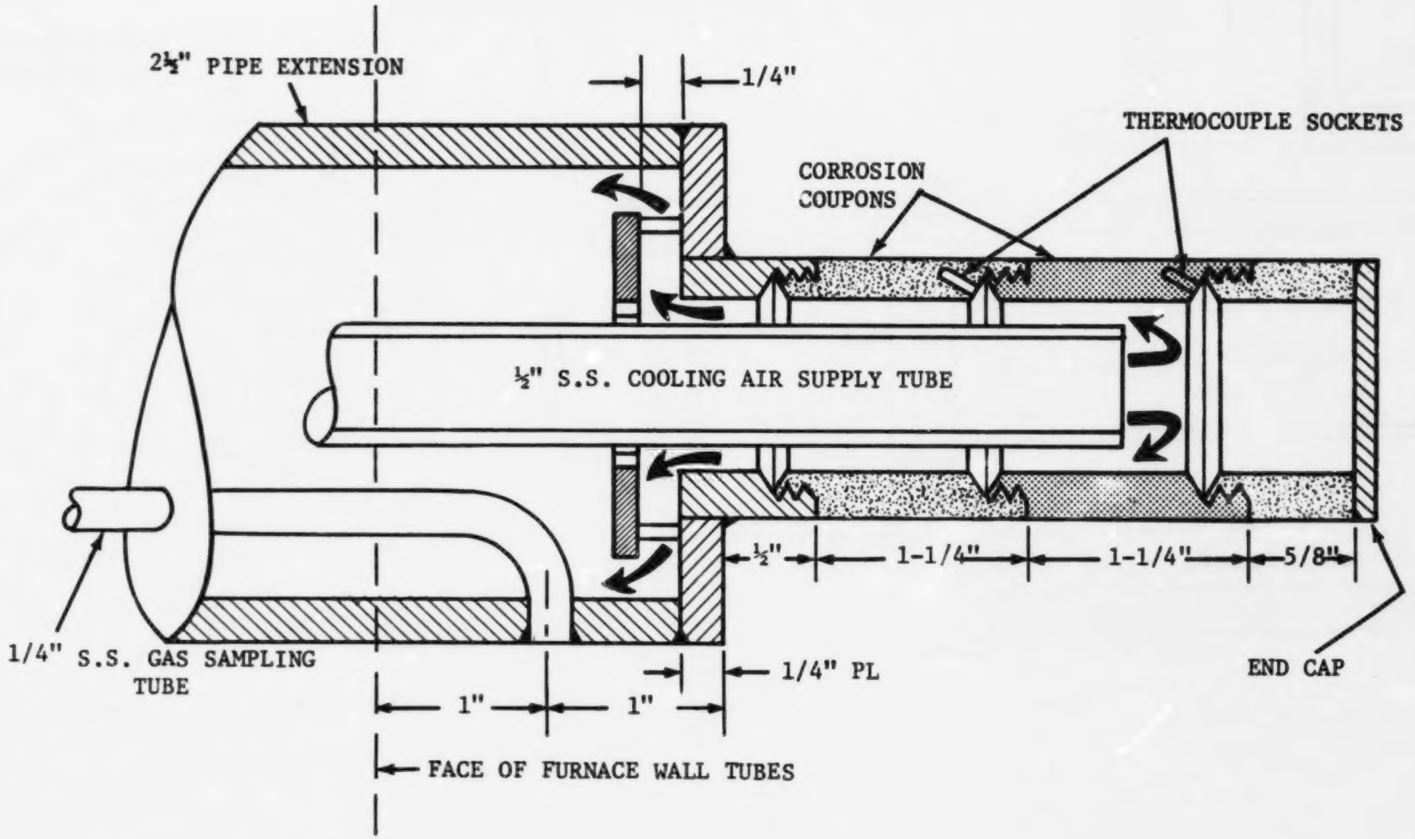

DRILLED AND TAPPED FOR 1/8" IPT THREAD
(SWAGELOCK FITTINGS - FOR THERMOCOUPLES)
END PLATE
WELD
2½" I.P.S. PIPE EXTENSION
1/16" THERMOCOUPLES (2)
HOLE DRILLED TO ACCEPT ½" SS AIR SUPPLY TUBING
AIR SUPPLY (½" SS TUBING)
1/4" GAS SAMPLING TUBING (SS)
SEAL WELD
WELD
HOLE FOR 1/4" SS GAS SAMPLING TUBE
END PLATE
SWAGELOCK FITTING DRILLED FOR ½" SS AIR SUPPLY TUBE (THREADS CUT OFF AND FITTING WELDED OR SILVER SOLDERED TO END PLATE)
AIR DISCHARGE
1-1/4" COUPLING

FIGURE 6

CORROSION PROBE

DETAIL OF CORROSION COUPON ASSEMBLY
(INSIDE OF FURNACE)


2½" PIPE EXTENSION
1/4"
THERMOCOUPLE SOCKETS
CORROSION COUPONS
½" S.S. COOLING AIR SUPPLY TUBE
½"
1-1/4"
1-1/4"
5/8"
1/4" S.S. GAS SAMPLING TUBE
1/4" PL
END CAP
1"
1"
FACE OF FURNACE WALL TUBES

Sustained, 300-hour corrosion probe tests were run on boilers of four utility companies, as shown in Table 4 below:

TABLE 4

SUMMARY OF CORROSION PROBING TESTS

		Boiler Number		
Utility	Station	Base	"Low NO_x"	Type of Firing
Georgia Power Co.	Harllee Branch	4	3	Horizontally Opposed
Utah Power & Light Co.	Naughton	3		Tangential
Arizona Public Service Co.	Four Corners	5	4	Horizontally Opposed
Alabama Power Co.	Barry	4	4	Tangential

3. FIELD TEST RESULTS

The field test results obtained on individual boilers under diverse operating conditions are presented in three sections. These sections consist of gaseous emission measurements, flue gas particulate loading measured upstream of particulate collector equipment, and corrosion probing data obtained in accelerated furnace fire-side water-tube corrosion tests. Gaseous emission and most of the particulate emission data were obtained under normal, as well as staged firing conditions. As discussed before, particulate loadings of the flue gas were determined only under conditions corresponding to baseline and "low NO_x" operation, for purposes of comparison on the relative effect of staged firing patterns on flue gas particulate loadings in coal combustion. Similar considerations apply to the sustained, 300-hour corrosion tests, which had as their objective the determination whether staged firing of coal accelerates furnace water tube corrosion rates.

The gaseous emission data obtained under baseline and staged firing conditions, at various load levels, are presented first. Throughout this paper, pollutant concentrations are expressed as ppm, adjusted to zero per cent O_2 in the flue gas, on a dry basis.

3.1 Gaseous Emission Results for Individual Coal-Fired Boilers

The data obtained are grouped according to boiler design type, i.e., wall-fired (front wall or horizontally opposed), tantentially fired, and turbo-furnace boilers.

3.1.1 Widows Creek Boiler No. 6

The Tennessee Valley Authority's Boiler No. 6 at their Widows Creek Station was the first boiler tested in our present study. Thirty-two short-term test runs were made in a statistically design optimization program, to minimize NO_x emissions. These tests were followed by two sustained runs, one at full load, the other one at reduced load, with the optimum staging patterns. The sustained corrosion probing run was deferred at TVA's request, until high sulfur coal could be fired, and other data would be available to show that staged firing would not cause abnormally high furnace corrosion rates.

Widows Creek Unit No. 6 is a 125 MW, 16-burner, front-wall, pulverized coal fired Babcock and Wilcox boiler. It has a single dry-bottom furnace with a division wall, and the 16 burners are arranged with four burners in each of four rows. Each row is fed with coal by a separate pulverizer.

The statistical test design shown in Table 1 for this boiler has been discussed earlier. The NO_x emission data, expressed as ppm NO_x corrected to zero per cent O_2 in the flue gas (dry basis) obtained with the various firing patterns tested are presented in Figures 7 and 8. In Figure 7, the measured emissions are plotted vs. per cent of stoichiometric air to the active burners. Figure 8 shows the same emission data, but plotted as a function of the overall per cent stoichiometric air. Corresponding to each firing pattern (designated by "S"), least squares regression lines have been fitted to the data points.

FIGURE 7

PPM NO_x (0% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(WIDOWS CREEK - NO. 6 BOILER)

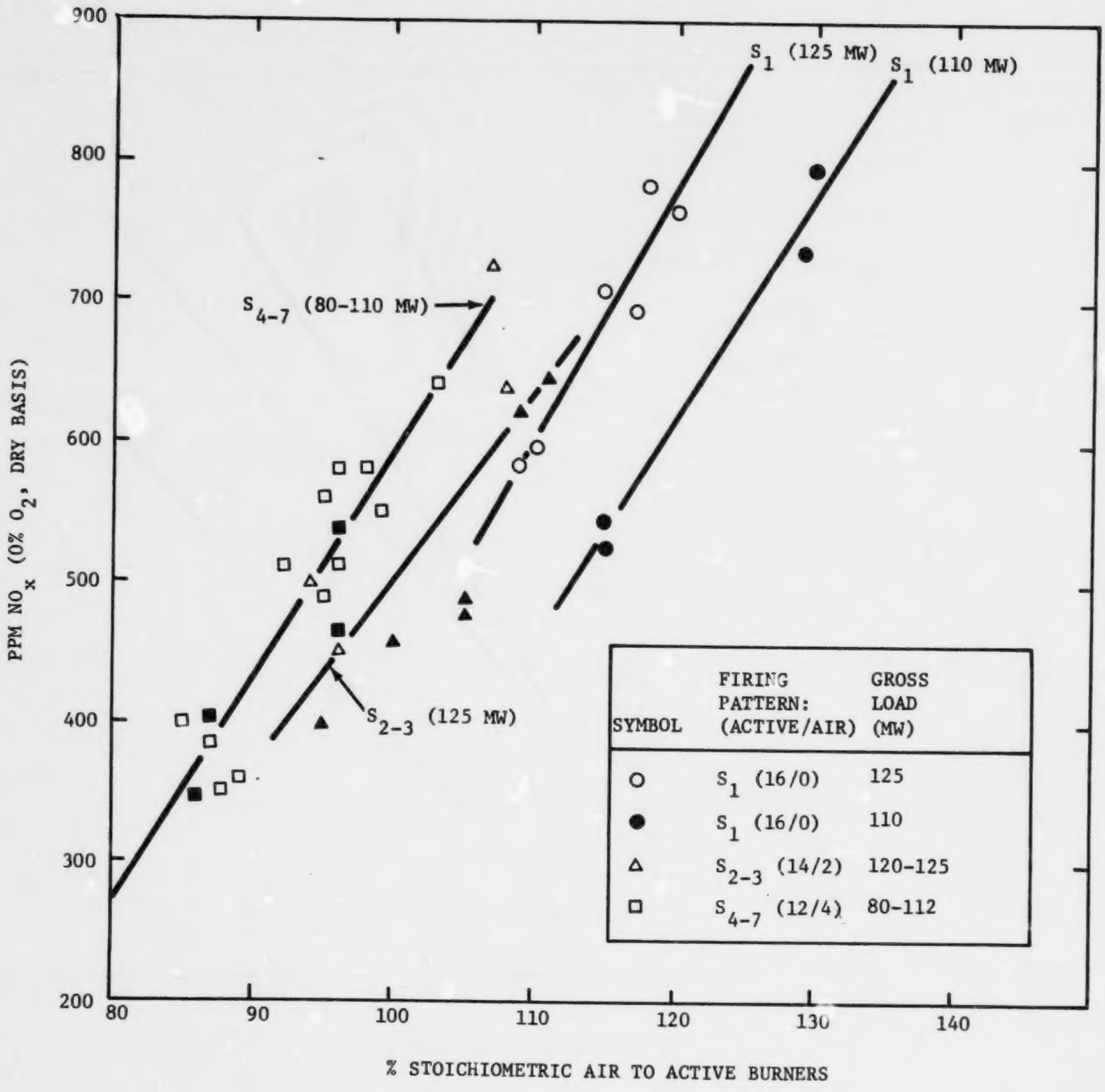
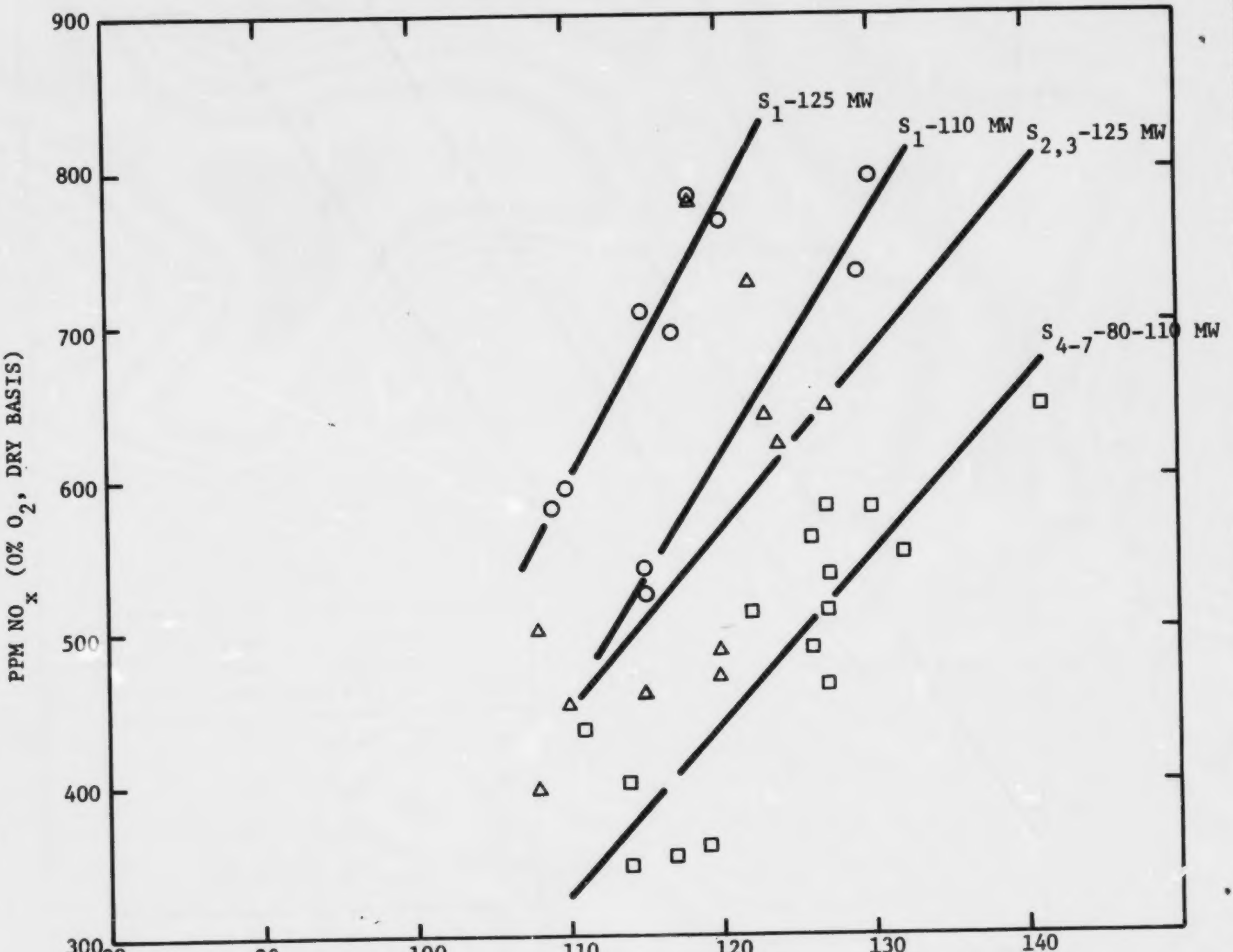


FIGURE 8

PPM NO_x (0% O_2, DRY) VS OVERALL STOICHIOMETRIC AIR

(WIDOWS CREEK - NO. 6 BOILER)



The data show the strong influence of reduced oxygen supply on decreasing NO_x emissions. This effect is further enhanced by staged firing patterns, as shown in Figures 7 and 8.

Low excess air operations consistently reduced NO_x emission levels. Average reductions were 23% under normal firing, 34% at full load staged operation and 27% at reduced load staged operation. Staged firing at full load resulted in an average of 14% NO_x reduction at full load, and an average of 27% at reduced load. The lowest practical level of excess air was dictated by acceptable CO emissions and stack appearance. The combination of low excess air and staged firing reduced NO_x emissions by 40% at full load, and from 33% to 50% at reduced load. The optimum combination of operating variables reduced NO_x by 47% at full load and by 54% at reduced load.

Of the firing patterns tested, operating the top row of burners on air only, with low overall excess air, gave the highest reductions in NO_x. Operating with the top wing burners on air only resulted in slightly lower NO_x emissions than with the bottom wing burners on air only.

Opening or closing down the secondary air registers was found to have small, but statistically significant effects on NO_x emission levels.

The data shown in Figure 7 call attention to an apparent anomaly. A cursory inspection of the data would indicate, that while as expected, NO_x levels decrease with decreasing air supply to the active burners, staging the burners could result in higher NO_x emissions than normal operation at the same burner air/fuel air ratio. The true interpretation of these data is that for staged burner configurations, it is generally necessary to operate at a higher overall level of air supply than for normal firing. Thus, for a given air/fuel ratio to the burners, the overall level of excess air is higher in staged firing than in normal operation. Furthermore, the desirable effect of heat removal between "first" and "second" stages is not as effective in staging the burners as when special "NO-ports" or "over-fire" air ports are available for secondary air admission. Thus, it is reasonable to expect that in new installations, designed for staged combustion, even higher NO_x reductions may be accomplished than in these tests which deliberately "de-activated" burners to achieve staging.

The foregoing remarks on comparing NO_x emissions with staging to those with normal firing, as a function of the per cent stoichiometric air to the active burners, are not unique to Widows Creek No. 6, but to all boilers tested, as will be shown later.

3.1.2 Crist No. 6 Boiler

Gulf Power Company's Boiler No. 6 at their Crist Station is also a front-wall fired unit. This Foster Wheeler boiler has a single furnace, with a maximum continuous rating of 345 MW gross load. Its 16 burners are arranged in four rows of four burners each.

A cooperative test program by Gulf Power, Foster Wheeler and Esso, coordinated by EPA, was planned for this unit. Plans included short-term firing pattern optimization runs for minimizing NO_x emissions, accompanied by boiler performance tests by Foster Wheeler, followed by boiler operability check-out at "low NO_x", than a sustained 300-hour test under "low NO_x" and baseline operating conditions for assessing corrosion problems, and an optional long-term test period of about 6 months for determining actual furnace water tube wastage.

Because of load demands on this boiler, to date it has been possible only to explore firing patterns in short-term runs, without performance tests, for minimizing NO_x from this boiler.

As shown by the data in Figure 9, the general trend of decreasing NO_x emissions with reduction of per cent stoichiometric air followed trends similar to those observed in the Widows Creek Boiler No. 6 tests. Again, NO_x levels decrease sharply with decreasing the % stoichiometric air to the active burners, including normal firing patterns.

The data in Figure 9 are subdivided into the "A" and "B" sides of the boiler. The flue gas stream leaving the furnace is split into these two ducting paths, and although the boiler operator and manufacturer could at times achieve O_2 balance in the two sides, the NO_x levels measured were clearly higher for the A side than the B side, with all firing patterns tested. The reason for this behavior is unexplained at present, although it may be related to differences in air flow, and uncertainties of the accuracy of air damper settings on the two sides of the boiler.

To simplify the presentation, Figure 9 shows only the least square regression lines fitted to the data points. S_1 denotes normal firing, while S_2, S_3, and S_4 are staged firing patterns, where S_2 denotes top row using burners on air only, S_3, top row middle burners on air only, and S_4, all top row burners on air only. Combining all data points for the A and B sides of the boiler, respectively, results in the two similar, although not quite parallel least squares regressions shown in heavy lines, indicating similar trends.

As expected, the S_3 pattern results in somewhat lower NO_x emission levels than the S_2 pattern, because of the larger spacing between active burners in the former configuration. The most effective combustion modification is, of course, operating the top row burners on air only (S_4) with low overall excess air, but for this boiler, such a firing pattern entails a load reduction of about 15%.

It is hoped that eventually an opportunity may arise for completing the planned program on this unit.

3.1.3 Harlee Branch Boiler No. 3

Georgia Power Company's No. 3 Boiler at their Harlee Branch Station was tested through all three phases of our test program procedure. In this section of the present paper, the gaseous emission results are summarized while particulate measurements and corrosion probing results will be presented later.

Harlee Branch unit No. 3, with a maximum rated capacity of 480 MW gross load, is a single furnace, pulverized coal fired Babcock and Wilcox boiler. It has 40 burners arranged in twenty burner cells of two burners each, with two rows of five burner cells located in both the front and rear walls of the furnace. The burner configuration and pulverizer layout are shown in Figure 10 for this boiler.

FIGURE 9

PPM NO_x (0% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(CRIST NO. 6 BOILER)

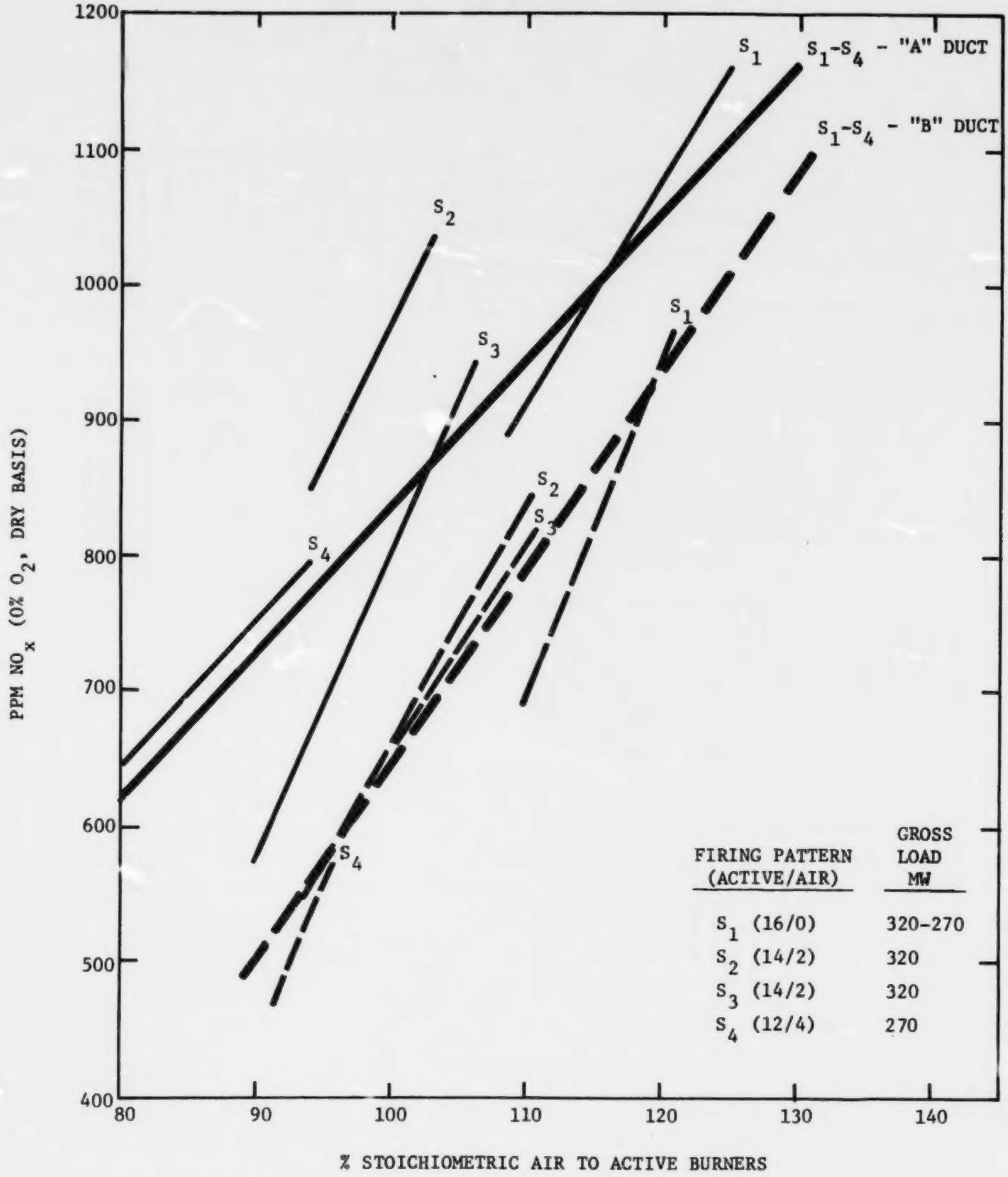
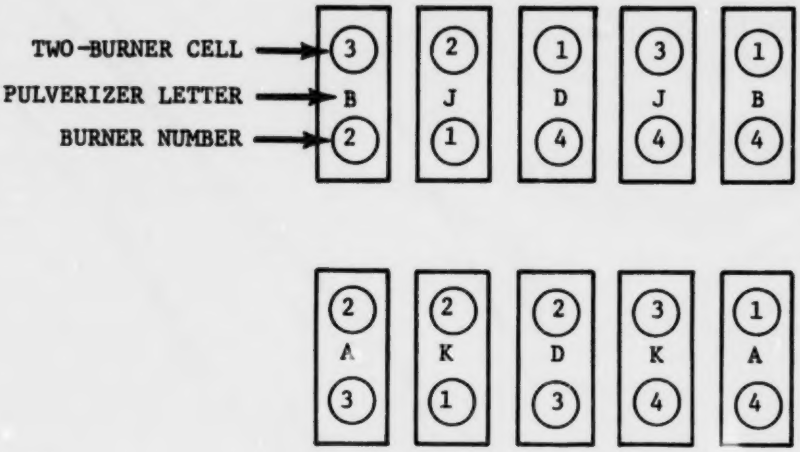
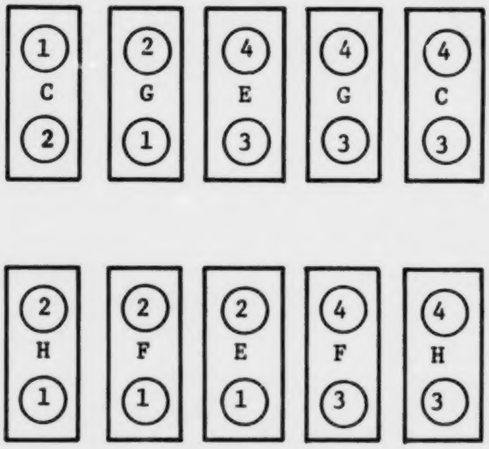


FIGURE 10

HARLLEE BRANCH NO. 3 BOILER PULVERIZER AND COAL PIPE LAYOUT


TWO-BURNER CELL
PULVERIZER LETTER
BURNER NUMBER
③ B ②
② J ①
① D ④
③ J ④
① B ④
② A ③
② K ①
② D ③
③ K ④
① A ④

FACING REAR FACE


① C ②
② G ①
④ E ③
④ G ③
④ C ③
② H ①
② F ①
② E ①
④ F ③
④ H ③

FACING FRONT FACE

Because of the arrangement of pulverizer mills for this boiler, it was possible to shut off the coal supply through individual pipes, and therefore, there was added flexibility for exploring staging patterns during the short-term testing phase.

Baseline NO_x emission levels averaged about 870 ppm. Lowering the level of excess air was possible both under normal and staged operating conditions down to flue gas O_2 concentrations of about 1.5% or even lower, without apparent undesirable side effects. The steep effect of reducing the per cent of stoichiometric air to the active burners on decreasing NO_x emissions is shown by the least squares regressions of the data in Figure 11. This figure combines the data obtained under normal firing using 40 burners, with those measured using a large variety of burner staging patterns.

Interestingly, by operating four to six top burner cell row burners on air only, it was possible to maintain boiler load at 480 MW, and reducing the NO_x emission levels to about 580 ppm. This level corresponds to a reduction in NO_x of about one-third, compared with the baseline level. Usually, using burners of the top rows of front and rear walls were operated on air only, but the NO_x emission levels were not particularly sensitive to the exact location of the inactive burners in the top row.

With only 30 active burners, i.e., 10 top row burners on air only, it was possible to reduce NO_x emissions to about 390 ppm at low levels of excess air, or a reduction of over 50% from the baseline level. However, load was also reduced by 17% from 480 MW to 400 MW using this staging patterns.

For the 300-hour sustained run, a full load, low excess air condition (overall 107% stoichiometric air, with three wing burners on both front and rear faces of the boiler on air only) was selected.

3.1.4 Four Corners Boiler No. 4

Arizona Public Service's No. 4 Boiler at their Four Corners Station was also tested according to our test program design, except that continuous electricity demand on the station prevented testing at low loads, and the currently inoperative flue gas recirculation system could not be utilized. This unit, with a maximum rated capacity of 800 MW gross load, is a single furnace (with division wall), pulverized coal fired Babcock and Wilcox boiler. It is fired with low sulfur, high ash Western coal. Boiler No. 5 at the Four Corners Station is a "sister"-unit of similar size and design. The latter was used for determining accelerated furnace water tube corrosion rates under baseline operating conditions.

In each of these two boilers, nine pulverizers feed 54 burners, arranged in 18 cells of three burners each, as shown in Figure 12. The front wall has ten burner cells, while eight burner cells are located in the rear wall of the furnace. Each boiler can maintain the full load capacity of 800 MW with eight or nine pulverizers in operation, when good quality coal is fired, and all equipment is in good operating conditions.

FIGURE 11

PPM NO_x (0% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(HARLLEE BRANCH - NO. 3 BOILER)

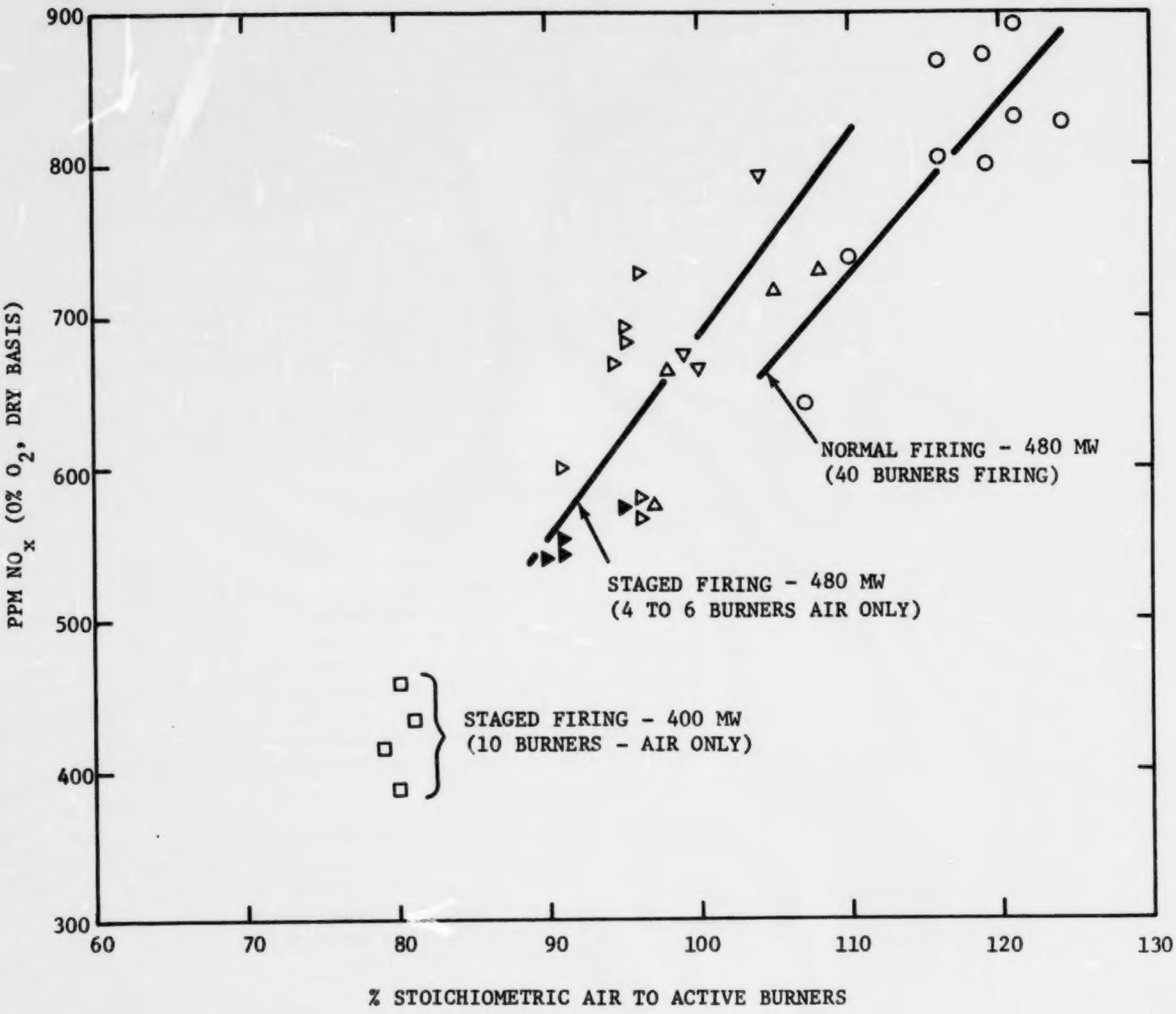
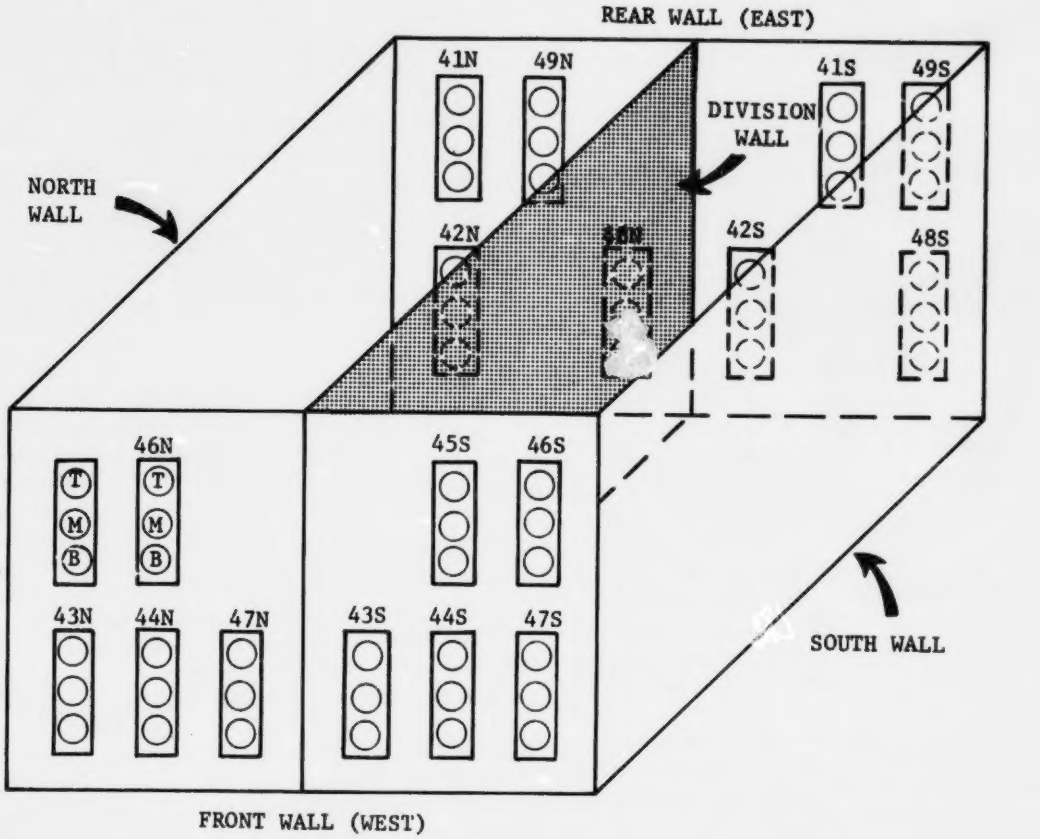


FIGURE 12

FOUR CORNERS STATION - BOILER NO. 4
PULVERIZER-BURNER CONFIGURATION


REAR WALL (EAST)
41N
49N
41S
49S
DIVISION WALL
NORTH WALL
42N
48N
42S
48S
46N
45S
46S
T
M
B
T
M
B
43N
44N
47N
43S
44S
47S
SOUTH WALL
FRONT WALL (WEST)

9 PULVERIZERS NUMBERED 41 THROUGH 49.
18 BURNER CELLS NUMBERED WITH PULV. NO. "N" OR "S" FOR NORTH OR SOUTH OF DIVISION WALL.
54 BURNERS DESIGNATED "T", "M" OR "B" FOR TOP, MIDDLE OR BOTTOM OF EACH CELL.

E.G., 45NT IS TOP LEFT BURNER IN FRONT WALL OF NO. 4 BOILER
→ TOP BURNER OF CELL
→ NORTH SIDE OF DIVISION WALL
→ NO. 5 PULVERIZER
→ NO. 4 BOILER

Operating variables during the short-term optimization phase of the tests were boiler load, burner firing pattern, excess air level and secondary air register setting. Our gaseous sampling system was modified to allow sampling from 18, instead of the usual 12 duct positions, with two three-probe assembly each in the north, middle, and south ducts between the economizer and the air heaters.

The NO_x emission data measured are summarized in Figure 13. Baseline NO_x emissions under normal operating conditions averaged a high level of about 1070 ppm, which is consistent with that expected from a large, horizontally opposed, coal-fired boiler. Reducing the per cent stoichiometric air to the active burners sharply reduced NO_x emissions for both normal and staged firing.

Staged firing with 46 active burners (eight top burners on air only) resulted in further reductions in NO_x, particularly when the per cent stoichiometric air to the active burners was decreased below 100%. As shown by the least squares regressions of the data in Figure 13, NO_x emissions could be reduced by about 45% to 570 ppm, with 95% of the stoichiometric air supplied to the active burners. Even further reductions in NO_x could be achieved at the full load of 800 MW by operating 12 burners on air only, to 530 ppm, or a reduction of 50%.

Wide open secondary air register settings could reduce NO_x emissions by a small amount compared with closed settings (presumably because of reduced combustion intensity), but only in combination with low excess air firing. As before, the effect of damper settings on NO_x emissions was significant, but second-order with respect to the main effects of reduced excess air and staging.

As for the boilers discussed before, the plot of ppm NO_x vs. per cent stoichiometric air to the active burners shows the effect of staging. Again, the apparent dichotomy of higher NO_x emissions measured under staged firing conditions than for baseline operation at the same levels of per cent stoichiometric air is due to the fact that the overall excess air is higher at the same burner air supply for staging than for normal firing.

The solid triangle data points obtained with staged firing (46 active burners, eight burners on air) were measured while the boiler operator used water injection to help improve precipitator efficiency for particulate removal. The rather impressive reduction in NO_x of over 100 ppm from about 700 ppm is not altogether surprising, based on our estimate of 0.2 lb. H_2O injected/lb. coal fired. This quantity of water injection should reduce flame temperatures sufficiently to allow for the above degree in NO_x emission reduction.

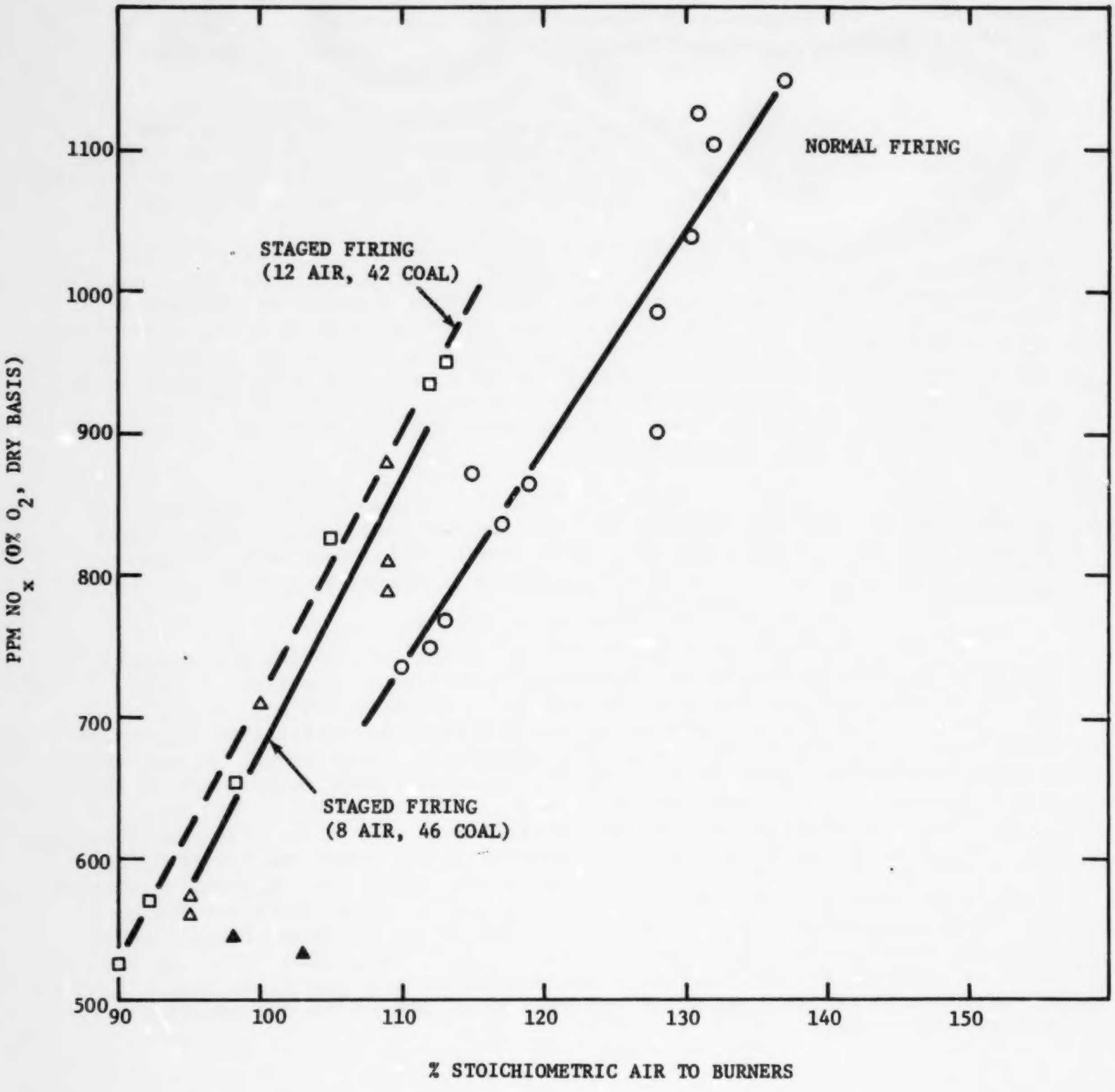
3.1.5 Naughton Boiler No. 3

Utah Power and Light's No. 3 boiler at their Naughton Station was one of two modern, 350 MW maximum rated single furnace, pulverized coal fired, Combustion Engineering boilers tested. The other one was Alabama Power's No. 4 Boiler at their Barry Station. Both boilers have five levels of four corner burners each. Gaseous emission results obtained in testing the latter will be presented in the next section of this paper.

FIGURE 13

PPM NO_x (0% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(FOUR CORNERS NO. 4 BOILER)



Naughton unit No. 3 was designed to fire a sub-bituminous, low heat content (9,500 Btu/lb. HHV), low sulfur, high moisture content Western coal. The boiler was designed for a larger turbine-generator than the one actually installed. This factor, in combination with the lack of "seasoning" of the superheat and reheat surfaces, and the type of coal fired in this new unit has resulted in a steam temperature control problem. The use of tilting burners and attemperation water are the means available for controlling steam temperatures. To the date of our test, it has been necessary at load levels exceeding 280 MW to tilt the burners down, add attemperation water, lower excess air and use furnace soot blowers almost continuously. It may be necessary, according to Combustion Engineering representatives, to reduce the reheat surface area to overcome this control problem.

Other operating problems encountered in this test program were furnace slagging (particularly at high loads, with low excess air and tilting burners down) even under normal operating conditions, and the high silica content of the boiler feed-water, causing pin-hole leaks in the condenser tubing.

The above problems were taken into account for the design of the statistical test program. Our short-term, NO_x optimization phase was conducted at less than full load levels, to avoid the limited flexibility associated with operating problems. The six operating variables studied in the short term optimization tests were gross boiler load, burner firing pattern, excess air level, burner tilt, secondary air damper setting, and coal pulverizer fineness setting. Because of the above-mentioned operating problems with this new boiler, the 300-hour accelerated test was performed only under normal operating conditions, as will be discussed later.

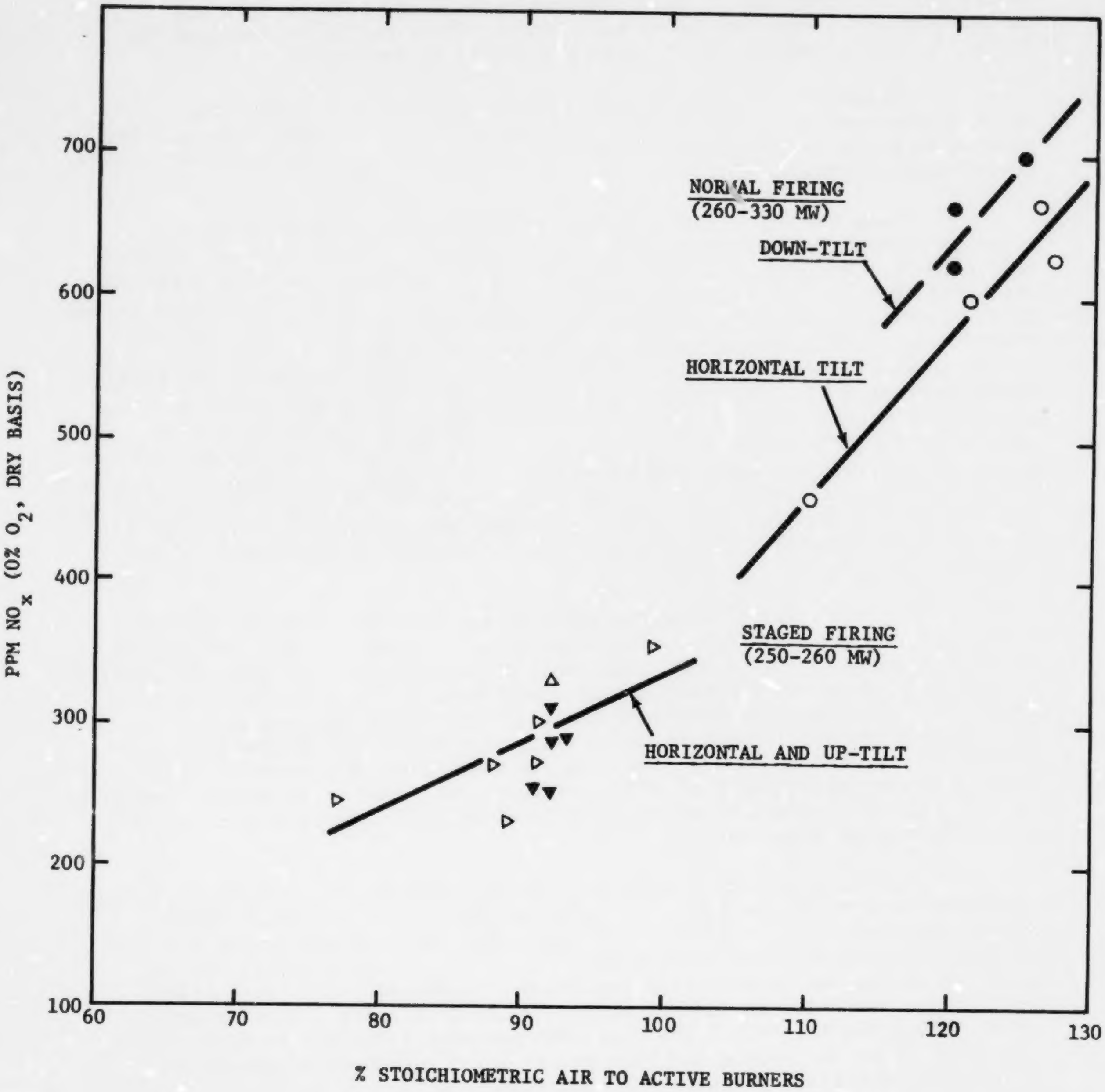
Normal classifier fineness, horizontal or down-tilt burner position, and low coal-air register settings resulted in the lowest NO_x levels. Based on these initial findings, most of the NO_x optimization test were run under these conditions, to explore the effectiveness of the major variables, staging and excess air, on NO_x emissions.

The emission data obtained are in testing this boiler are shown by the least square regressions of Figure 14. Significant reductions in NO_x emissions were achieved from the baseline level of about 650 ppm (which is relatively low for a coal fired boiler of this size, but typical of tangential fired units, from the standpoint of NO_x emissions). With normal firing, quite a steep decrease was found by reducing the per cent stoichiometric air to the active burners to 110%, resulting in a reduction by about 30% to 450 ppm. Staged firing in combination with low overall excess air (less than stoichiometric air/fuel ratio in the active burners) resulted in NO_x levels as low as 250 ppm, or a reduction of about 60% from the baseline NO_x level. The highest reductions in NO_x were achieved with "abnormal" air register settings (coal-air 30% open, and auxiliary air 70% open), as opposed to the normal settings of coal-air 80% open, and auxiliary air 20% open. Additional small reductions in NO_x emissions could be obtained through the use of optimum burner tilt positions, and pulverizer mill fineness, each contributing about 10% to the NO_x emission reductions achieved.

FIGURE 14

PPM NO_x (0% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(NAUGHTON STATION, NO. 3 BOILER)



3.1.6 Barry Boiler No. 4

Alabama Power's Boiler No. 4 at their Barry Station was tested successfully through all three phases of our test program design. Representatives of Combustion Engineering actively participated in this series of tests. As mentioned before, this new 350 MW maximum rated capacity, single furnace, pulverized coal fired Combustion Engineering boiler is similar to Naughton unit No. 3. Both are representative of that manufacturer's current design practices. In Barry No. 4, five pulverizers feed 200 burners that are corner-mounted at five levels of the furnace. This boiler is designed for firing Eastern bituminous coal, having a HHV of 12,000 Btu/lb.

Altogether, 35 statistically designed short term period NO_x optimization runs were made during the first phase of the test program. The gaseous emission data obtained in this phase are presented in the least squares correlations of Figure 15.

Among the minor operating variables from the standpoint of NO_x emission control, burner tilt position had the most promised effect, as shown in Figure 15. Horizontal and 30° up-tilt burner positions produced lower NO_x emissions than the 30° down-tilt position, particularly with all burners firing coal. Varying burner tilt position, of course, has as its primary purpose to control steam temperatures. With the burners tilted down, a large proportion of the combustion process occurs in the direction of the bottom of the furnace (hence increased slagging there), and higher peak flame temperatures at longer gas residence times produce more NO_x. These increased NO_x levels can be partially offset by the ability to operate at lower excess air levels with the down-tilt position, as more residence time is available for burn-out of the fuel. With horizontal or up-tilt burner positions, there may be less than one complete rotation of the swirling gases before reaching the boiler arch, which can lead to some stratification (about one per cent difference in O_2 between "A" and "B" ducts.

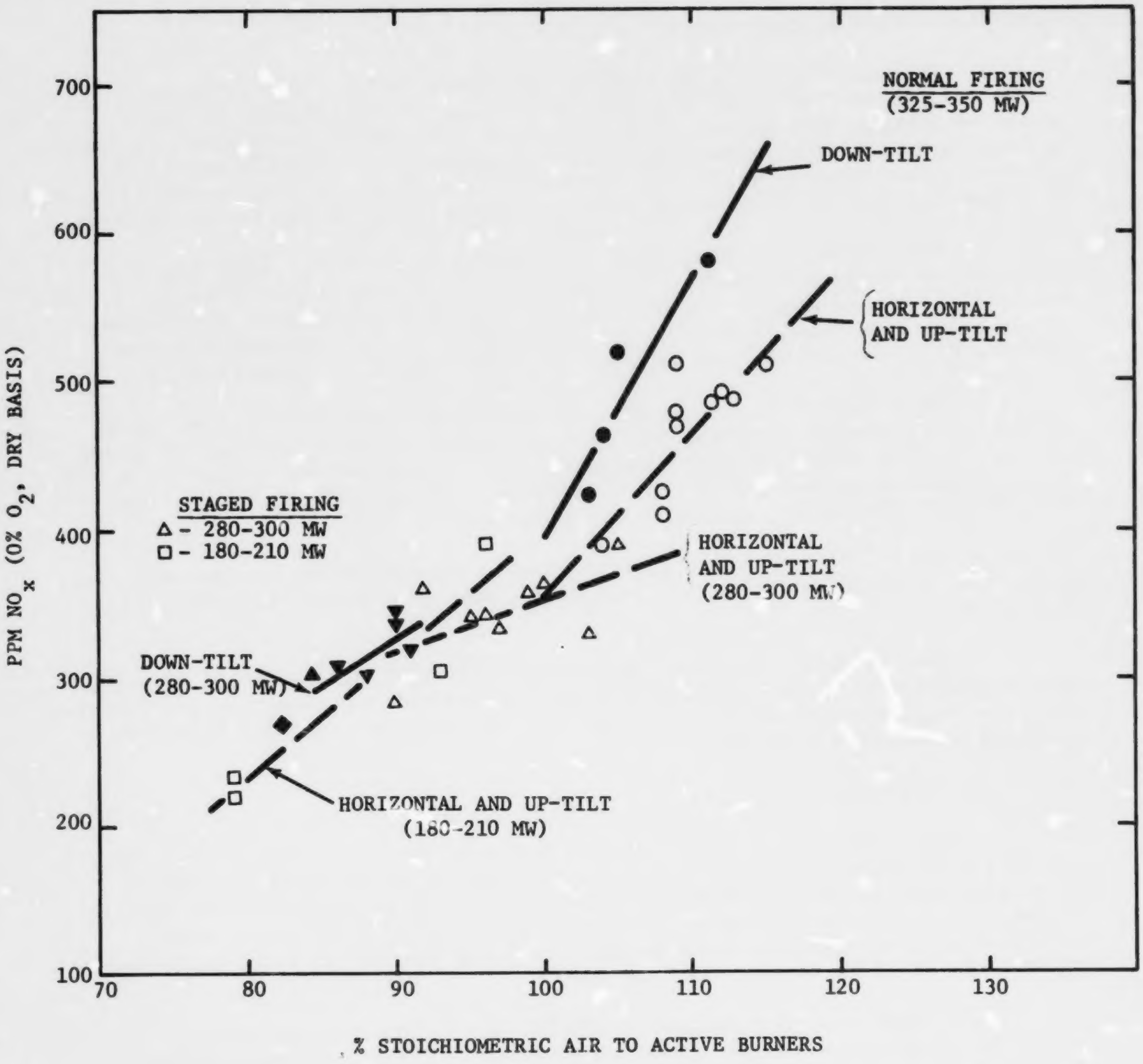
The other minor variables studied, air register settings and coal pulverizer fineness, did not produce significant changes in NO_x. As expected, the most pronounced effect on NO_x was that of reducing the per cent stoichiometric air to the burners under normal firing conditions, as shown by the data of Figure 15. From baseline levels of about 510 ppm (these remarkably low levels are likely to be due in part to the ability to operate this boiler with only 10% excess air, and in part to the slightly lower bound N-content of Alabama and Midwestern coals than that of the Western coal fired at Naughton), reducing the per cent stoichiometric air to 104% resulted in NO_x emissions of 390 ppm, or a reduction of about 23%.

Further significant reductions in NO_x were achieved by staged firing, admitting air only to the top level burners, and operating four or three pulverizers, depending on load conditions. With only one pulverizer inactive, and supplying 90% of the stoichiometric air to the active burners, the NO_x level was as low as 290 ppm, or a reduction of about 43% from the baseline level with a reduction in load of about 15% due to staging. Interestingly, the NO_x level was slightly higher, and the per cent reduction somewhat lower than those found in testing Naughton Boiler No. 3, presumably because of differences in boiler operation and coal type.

FIGURE 15

PPM NO_x (0% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(BARRY STATION NO. 4 BOILER)



Significantly, no slagging problems were encountered in testing Barry unit No. 4 even at the lowest levels of excess air used (as opposed to Naughton) and consequently, the 300-hour sustained "low NO_x" run could be made under excellent conditions.

3.1.7 Barry Boiler No. 3

Alabama Power Company's Boiler No. 3 at their Barry Station was tested at the boiler operator's request for gaseous emissions only in a short-term optimization program.

This unit is a 250 MW maximum continuous rating, twin furnace, tangential, pulverized coal fired Combustion Engineering boiler. It has a separated furnace arrangement, with radiant and horizontal superheater surfaces in both furnaces. The pendant and platen sections constitute the superheat surface in one furnace, and reheat surface in the other one. Six pulverizers feed 24 tangential burners (six levels of four burners) in each of the two furnaces.

This boiler was of special interest, because of the small value of 31.25 MW per "equivalent furnace firing wall". Our correlation based on previously obtained data for coal fired boilers (4) would predict a baseline NO_x emission level of 475 ppm for this parameter. Actual measurements gave baseline NO_x value of 479 ppm, in good agreement with the correlation.

Operating variables included in the actual test program were excess air level, air damper settings, and mill pulverizer fineness setting. Planned reduced load and staged firing tests could not be implemented, because mechanical problems with a condenser water valve prevented such operation, despite all the efforts of the plant personnel to correct the problem.

As expected, excess air level exerted a major effect on NO_x emissions, while that of damper settings was very small, and that of mill fineness was negligible.

These results are shown in the least squares regressions of Figure 16. From a baseline level of about 530 ppm at 122% stoichiometric air to the burners, NO_x emissions were reduced by about 32% (in line with our previous experience) to 360 ppm at 106% stoichiometric air.

3.1.8 Big Bend Boiler No. 2

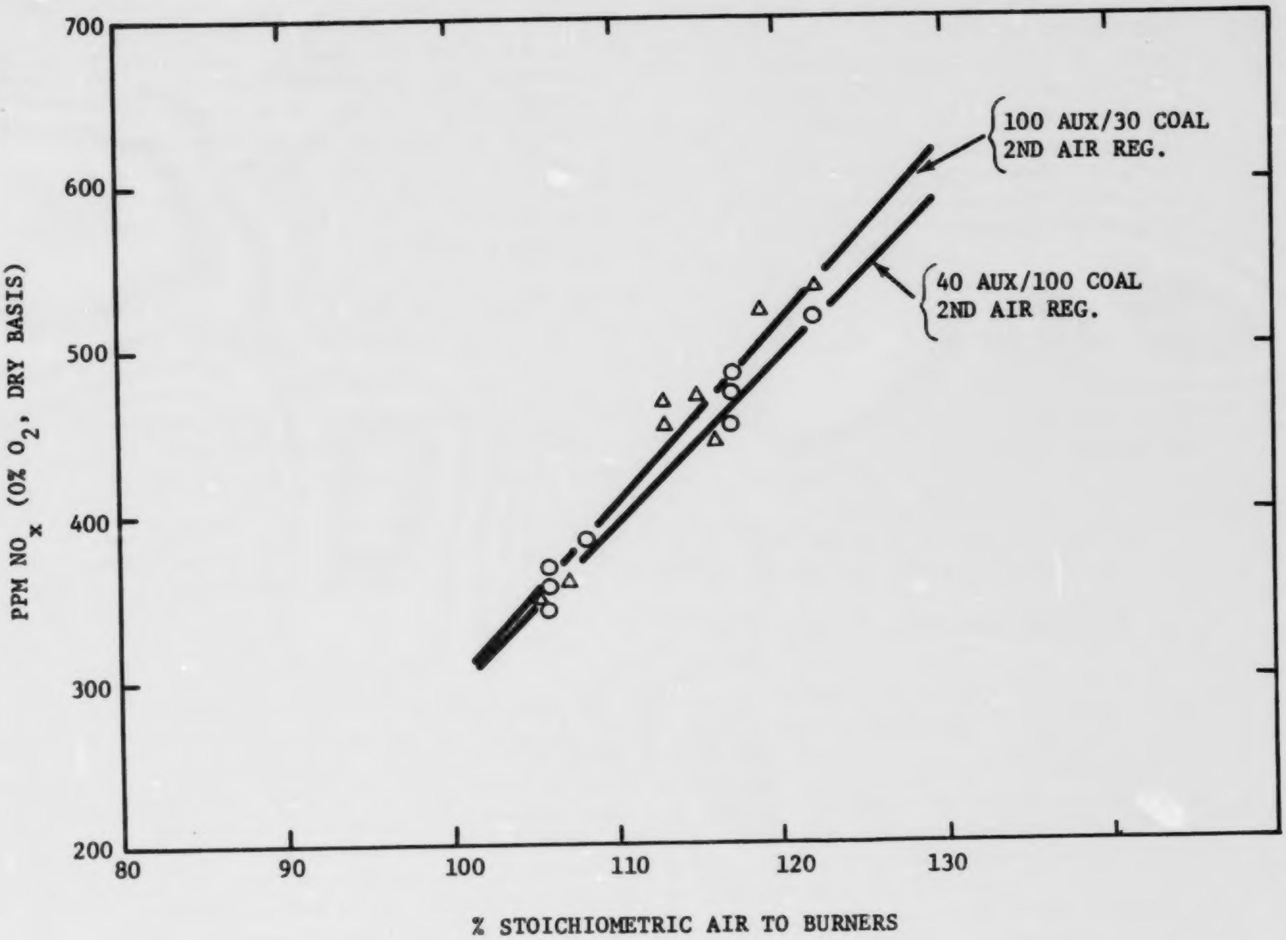
Tampa Electric Company's Boiler No. 2 at their Big Bend Station has been the only Riley-Stoker turbo-furnace unit tested by us to date. This pulverized coal fired, 450 MW maximum continuous rating, single furnace boiler is fed by three pulverizer mills. Altogether, 24 Riley directional flame burners are fired normally, with one row of 12 burners in the front wall, and another row of 12 burners in the rear wall.

Maximum load was limited to 375 MW, due to steam temperature, potential slagging, and other operating problems. (It is our understanding that gross load on this unit has never exceeded 400 MW.) Excess air was set at normal operating levels, or at the minimum level dictated by maximum acceptable CO levels measured in the flue gas, and in the slag catcher at the bottom of the furnace. Other operating variables included in the statistically design short-term phase (this was the only phase of our overall program design performed

FIGURE 16

PPM NO_x (0% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(BARRY NO. 3 BOILER)



at Big Bend) were operating with fly-ash reinjection (practiced to improve carbon burn-out efficiency and slagging characteristics) or without it, and positioning of the directional air vanes. Normal position is 15° below the horizontal for the air vanes. During our tests, they were aligned either 15° below the normal position, in both front and rear burners, or the front directional vanes were set at 15° below the normal position, and the rear directional vanes 15° above it. Simulated "staged" firing, at reduced load levels, was attempted by opening up the secondary air registers on selected burners, so that the active burners were supplied with 80% of stoichiometric air.

The NO_x emission results obtained are shown in the least squares regression of Figure 17. Reducing the air to the burners from the normal level of 115% of stoichiometric to 107%, decreased NO_x emissions from about 675 ppm at 370 MW to 470 ppm with 107% of stoichiometric air, or a reduction of about 45%. This decrease in NO_x with reducing excess air is steeper than that generally observed in wall and tangentially fired units. On the other hand, it should be noted that the "baseline" NO_x emission was determined at a load reduction of 18%, compared with maximum continuous rating. Further load reduction produced, as expected, further decreases in NO_x.

"Staged" firing, which in this instance was quite different from the normal pattern of staging burners, produced only a 10% reduction in NO_x at the low load of 230 MW, as shown in Figure 17.

The best NO_x reductions were obtained with front wall directional air vanes tilted 15° down, and rear vanes tilted 15° up from their normal alignment. Fly-ash reinjection had no significant effect on NO_x emissions.

Further testing is required with coal-fired turbo-furnace boilers to define optimum operation for NO_x control, taking into account steam temperature control, slagging, and potential fire-side water-tube corrosion problems.

3.2 Particulates Emission Results

All particulate testing, except for the tests at Utah Power and Light Company's Naughton Station, boiler No. 3 was done in the flue gas ducts downstream of the regenerative air heaters. Normally, determinations of the oxygen content of the flue gases (and other species analyses) are made on samples taken upstream of the air heaters in order to eliminate dilution due to air leakage in the air heaters. In order to reduce calculated particulate emissions to a standard basis, however, the oxygen content of the flue gases downstream of the air heater, where the particulate measurements are made, must be known. To obtain data on air heater leakage, traverses were made in the flues downstream of the air heaters. These data indicated an average leakage of about 8 percent. Tabulations of flue gas oxygen content after the air heaters shown in Table 5, therefore, were calculated using this average leakage factor. The exception is the Alabama Power Company tests where gaseous emission analyses were made on samples taken downstream of the air heaters and, therefore, require no correction.

FIGURE 17

PPM NO_x (0% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(BIG BEND NO. 2 BOILER)

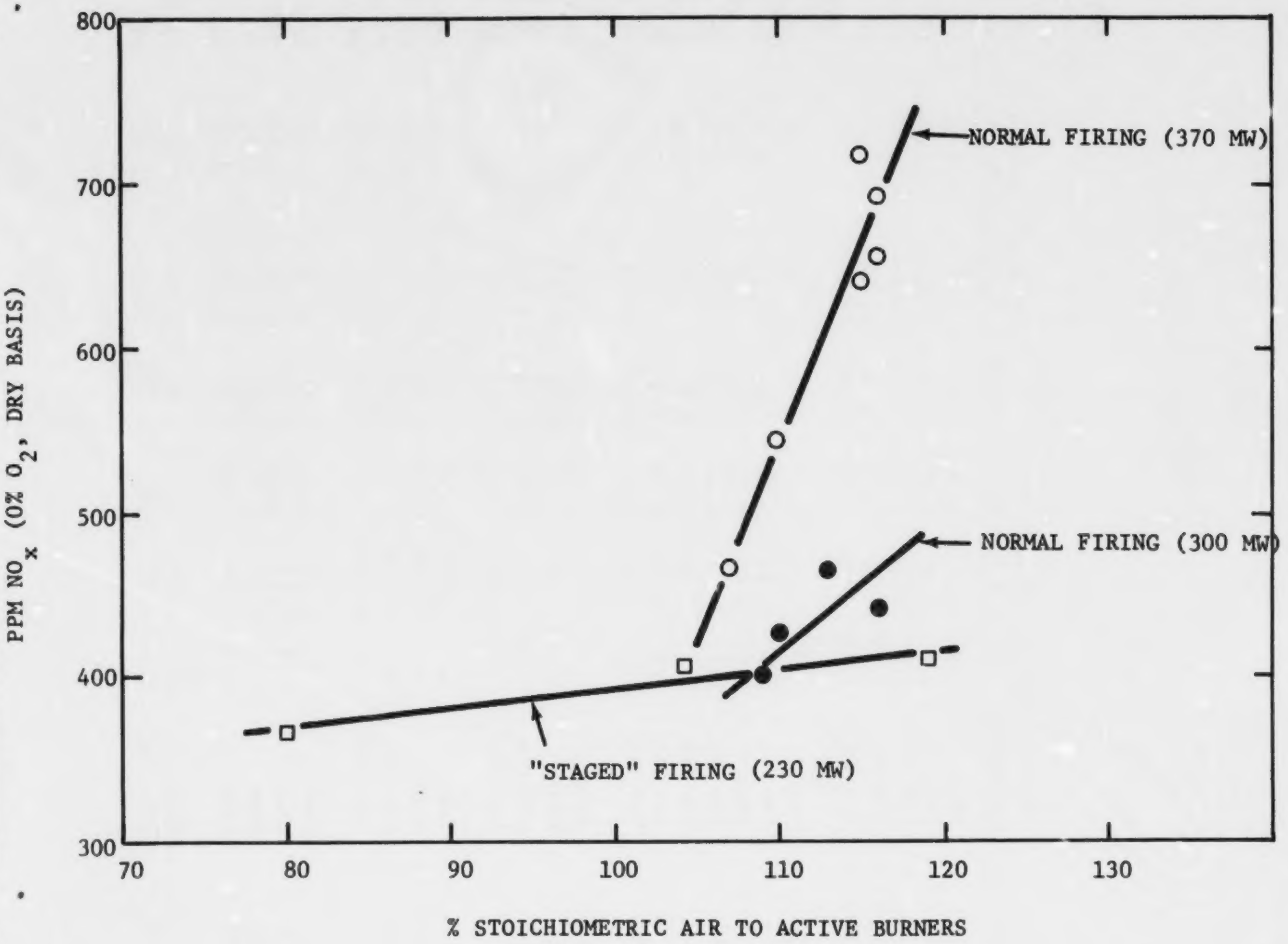


TABLE 5

PARTICULATE DATA

Utility	Test No.	Firing Condition	O_2 Before A.H.	Calc. O_2 After A.H.	Av. Gr/SCF @ Std. Cond.	Gr/SCF @ 0% O_2	lb./10^6 BTU	Grams/ 10^6 cal.	Reqd. Efficiency To Meet 0.1 lb/ 10^6 BTU	% Carbon on Particulate	Coal Ash Wet, %	HHV BTU/lb. Wet
TVA	1A	Base	3.9	5.17	2.68	3.55	4.65	8.37	97.85	6.29	15.87	11,452
	1B	Base	3.6	4.89	4.62	6.02	7.89	14.20	98.73	5.90	18.39	11,477
	10-C-1	Low NO_x	3.05	4.38	2.32	2.93	3.84	6.91	97.40	10.55	11.5	11,918
	10-C-3	Low NO_x	3.23	4.55	3.36	4.29	5.62	10.12	98.22	8.46	14.38	11,231
	26-A-1	Low NO_x	2.73	4.09	3.13	3.89	5.10	9.18	98.04	12.40	15.39	10,961
Georgia Power Company	1C	Base	3.0	4.34	1.83	2.31	3.03	5.45	96.70	5.50	12.05	12,310
	1D	Base	3.7	4.99	1.86	2.44	3.20	5.76	96.88	3.17	9.72	12,589
	1E	Base	3.5	4.80	2.26	2.93	3.84	6.91	97.40	2.80	8.58	12,121
	1G	Low NO_x	1.2	2.67	2.47	2.83	3.71	6.68	97.30	6.73	11.28	12,200
	1H	Low NO_x	1.3	2.76	2.60	2.99	3.92	7.06	97.45	11.82	8.43	12,574
	52D	Low NO_x	1.9	3.32	2.00	2.38	3.12	5.62	86.79	9.98	10.3	11,178
	52E	Low NO_x	2.0	3.41	2.65	3.16	4.14	7.45	97.58	7.41	11.86	11,887
Arizona Public Service Co.	1E	Base	3.44	4.75	4.52	5.84	7.65	13.77	98.69	0.69	21.92	8,821
	1F	Base	3.12	4.45	5.36	6.80	8.91	16.04	98.88	0.53	21.96	8,811
	12A	Low NO_x	4.28	5.52	4.87	6.40	8.38	15.08	98.81	0.18	23.13	8,913
	12B	Low NO_x	3.67	4.96	3.26	4.27	5.59	10.06	98.21	0.46	21.12	8,915
Alabama Power Company	42A	Base	--	5.03*	1.17	1.53	2.00	3.60	95.00	24.23	4.89	12,706
	42B	Base	--	4.49*	3.08	3.92	5.14	9.25	98.05	25.83	4.86	12,641
	19A	Low NO_x	--	4.64*	3.31	4.25	5.57	10.03	98.20	14.75	10.68	11,918
	19B	Low NO_x	--	4.34*	3.32	4.19	5.49	9.88	98.18	18.77	8.82	12,720
Utah Power & Light Co.	23	Base	3.56	4.86	0.448	0.58	0.76	1.37	86.91	22.62	8.16	10,293
	23	Base	3.56	4.86	0.301	0.38	0.51	0.92	80.55	22.62	8.16	10,293
	25	Base	4.31	5.55	0.752	0.34	0.44	0.81	77.73	4.44	6.78	10,273
	26	Base	4.46	5.69	0.800	1.10	1.48	2.59	93.04	1.80	8.10	9,992
Gulf Power Co.	1	Base	3.6	4.89	2.54	3.31	4.34	7.81	97.70	5.08	Not Yet Available	
	26B	Low NO_x	3.4	4.71	3.82	4.92	6.45	11.61	98.45	8.15		

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* Actual (not calc.)

Average emission data in grains per cubic foot at standard conditions were calculated from the particulate data obtained in the tests and are listed in Table 5. These data are also presented in terms of grains per SCF at zero percent oxygen, pounds per million BTU and grains per million calories. For comparison purposes, a calculation of the required precipitator collection efficiency to meet current federal standards of 0.1 pounds per million BTU fired is included in Table 5.

Tennessee Valley Authority

As indicated in Table 5, five particulate tests were made at TVA. The unit tested was boiler No. 6 at the Widows Creek Station. Two tests were run at baseline conditions and three at optimized "low NO_x" firing. Comparing results of tests 1A with 10-C-3 and 26-A-1, all conducted while firing approximately the same ash content coal, it can be seen that emissions increase from a baseline of 4.65 $lb/10^6$ BTU to 5.62 and 5.10 $lb/10^6$ BTU at "low NO_x" operation, respectively. The carbon content of the particulate in these tests increases from 6.29% at baseline to 8.46 and 12.40%, respectively, under "low NO_x" operation. Relatively small increases in electrostatic precipitator efficiency are required, however, to meet present standards, i.e., 97.85% to 98.22% and 98.04%, respectively.

Based on the data obtained on the No. 6, 125 MW, front wall fired boiler at TVA's Widows Creek Station, it appears that particulate emissions increase directionally, but not significantly, when "low NO_x" firing configurations are employed. Particulate carbon content which initially is relatively low on the TVA boiler, increases substantially (doubling in one case) under "low NO_x" firing conditions but the increases do not appear to be in direct relationship with the emissions or coal ash data. Only small increases in electrostatic precipitator collection efficiency would be required to accommodate the higher dust loadings produced with "low NO_x" firing. However, if real, the incremental increases at these levels of performance may be difficult and costly to achieve.

Georgia Power

A total of seven particulate tests were conducted on the No. 3, 480 MW, horizontally opposed fired boiler at Georgia Power Company's Harllee Branch Station, three at baseline or normal operating conditions and four while firing the boiler using "low NO_x" modifications. Particulate emission data for all tests were relatively consistent (see Table 5), ranging from 3.03 to 4.14 pounds per million BTU's fired. Average emissions at normal or "base" conditions were 3.36 $lb/10^6$ BTU compared to 3.72 $lb/10^6$ BTU for "low NO_x" producing conditions. Particulate carbon content was variable and again was inconsistent with other factors. Under normal firing conditions, percent carbon was reasonably low, varying from a low of 2.8 to 5.5 percent. At "low NO_x" operation these values ranged from 6.73 to 11.83 percent. Increases in the required precipitator efficiency to meet present standards again would be small, and probably of minor importance.

Arizona Public Service Company

Particulate test results obtained on the No. 4, 800 MW, horizontally opposed fired boiler at Arizona Public Service Company's Four Corners plant are of particular interest because of the low sulfur, high ash Western coal fired. Four tests were conducted, two under baseline and two under "low NO_x" operation. Particulate emissions, as expected, due to the high ash (∿ 23%) coal fired were high in all tests. Referring to Table 5, the results are somewhat confused by the high emissions obtained in one base run and the low emissions obtained in one of the "low NO_x" tests. However, if results of test 1E are compared with 12A, a more normal pattern is apparent. Particulate emissions of 7.65 lb/10^6 BTU for baseline operation (test 1E) increase to 8.38 lb/10^6 BTU for "low NO_x" test 12A. The increase, as in previous tests, is not substantial but is in line with what might be expected. Data on the percent carbon on particulates for all tests are startling. In the first place, the values are very low, averaging about 0.47%, confirming the easy burning qualities of Western coals. Secondly, particulate carbon content decreases with "low NO_x" firing as indicated in Table 5, from 0.695 and 0.528% in "base" tests 1E and 1F, respectively, down to 0.182 and 0.461% for "low NO_x" tests 12A and 12B, respectively. Thus, according to these data a benefit accrues to "low NO " operation with respect to unburned combustibles for this horizontally opposed fired boiler. With respect to precipitator performance, efficiency should only increase from 98.7 percent (baseline operation, test 1E) to 98.8 percent (low NO_x firing, test 12A) to accommodate the increased particulate emission produced under "low NO_x" firing conditions.

Alabama Power Company

Four dust loading tests were conducted on the 350 MW, tangential fired No. 4 boiler at Alabama Power Company's Barry Station, two at normal operation and two while using "low NO_x" emission reduction techniques. Referring to Table 5, the data obtained under baseline operation in test 42A appear to be unreliable. Comparing the results obtained in the other 3 tests (tests 42B, 19A & 19B) it can be seen that particulate emissions for this tangentially fired boiler increase from 5.14 lb/10^6 BTU under normal operation, to 5.57 and 5.49 lb/10^6 BTU when "low NO_x" emission techniques are used. Particulate carbon content for baseline operation (test 42B) of 25.83 percent (see Table 5) is very high, and considerably higher than for other types of firing. Surprisingly, substantial reductions in these carbon losses appear to occur with "low NO_x" operation. This behavior is shown by tests 19A and 19B with decreases in particulate carbon content down to 14.75 and 18.77 percent, respectively. Here again, "low NO_x" firing techniques apparently have beneficial results. Only nominal increases, probably of no major importance, are required in precipitator collection efficiency when employing "low NO_x" techniques.

Utah Power & Light Company

Tests for particulates on the 330 MW, tangentially fired, No. 3 boiler at the Naughton Station were made in the ducts leading into the air heaters, since downstream test locations were poor, and accessibility was limited. Four tests were run, all of which were conducted under normal or baseline firing conditions. Referring to Table 5 it can be seen that the emission values are not consistent with other data obtained in this study, especially in view of the consistency and levels of the ash content of the coal fired.

Since the tests were conducted in accordance with prescribed procedures, it is difficult to understand the reasons for these inconsistencies. One possible explanation is that the superheater and reheater surfaces on the No. 3 boiler were overdesigned necessitating operation with the burners at a horizontal position or tilted downwards. As a result, the lower furnace surfaces including the ash hopper slopes were slagged, while the superheater, reheater and convection section surfaces were extremely clean on this relatively new unit. It is possible that a major portion of the ash was impinging on the sticky slag particles and remained in the boiler, thus accounting for the low dust loadings.

The values reported for particulate carbon content are of interest. As shown in Table 5, it may be noted that carbon content in test No. 23 was 22.62 percent. This value is consistent with the high values reported for the Alabama Power Company tests (Tests 42A and 42B). Particulate carbon content reported for the latter, tangentially fired boiler was 24.23 and 25.83 percent, respectively, at baseline operating conditions. However, the values of 4.44 and 1.80% carbon content reported for tests 25 and 26 for normal operation are surprising since they are low and at variance with the Alabama Power Company test results for baseline conditions. More data on other tangentially fired boilers are required to resolve this apparent anomaly.

Gulf Power Company

Due to the limited scope of testing, particulate data were obtained in only two tests on the 320 MW, front wall fired, No. 6 boiler of Gulf Power Company's Crist Station. One was at normal operating conditions, and the other under "low NO_x" operating conditions. As shown in Table 5, the results appear to be in line with other emission data measured. Particulate emissions for baseline operation increases, as might be expected from 4.35 percent to 6.45 percent under "low NO_x" operating conditions. Similarly, carbon content of the particulate increases from 5.08 percent at normal operation to 8.15 percent when "low NO_x" burner configurations are used. Required precipitator efficiency to meet present standards would increase from 97.7% for base conditions to 98.4% to accommodate the higher emissions produced with "low NO_x" firing.

3.3 Corrosion Probing Results

As mentioned in section 2.2.3, corrosion probes were installed in the furnaces of the boilers tested, by inserting them through available openings closest to the areas of the furnace susceptible to corrosion, as indicated in Figure 4. Prior to installing the probes in the test furnace, the probes were prepared by mild acid pickling and pre-weighing the coupons, and screwing them onto the probes along with the necessary thermocouples. Each probe was then exposed to the furnace atmosphere prevailing for the particular type of operation desired for approximately 300 hours at coupon temperatures of about 875°F in order to accelerate corrosion. After exposure, furnace slag was cleaned off and saved for future analyses, and the coupons were carefully removed from the probes. In the laboratory the coupons were cleaned ultrasonically with fine glass beads to the base metal, and re-weighed to determine the weight loss. To date in our tests, corrosion rates have been determined for 40 coupons installed on 20 probes (2 coupons/probe), in boilers at four different generating stations as listed in section 2.2.3. Corrosion data obtained are tabulated in Tables 6 through 10.

TABLE 6

GEORGIA POWER COMPANY
HARLLEE BRANCH STATION

CORROSION PROBE DATA

Boiler No.	Firing Condition	Exposure Hrs	Probe No.	Coupon No.	Corrosion Rate Mils/Yr
3	Low NO_x	297	3A	6	27.5
				7	122.0
3	Low NO_x	297	3B	8	75.9
				9	155.0
4	Base	304	4A	10	75.3
				11	72.2
4	Base	304	4B	12	25.7
				13	47.9

TABLE 7

UTAH POWER & LIGHT COMPANY
NAUGHTON STATION

CORROSION DATA

Boiler No.	Firing Cond.	Exposure Hrs	Probe No.	Coupon No.	Corrosion MPY
3	Base	287.0	1	1	124
				2	65
3	Base	287.5	2	3	43
				4	47
3	Base	283.5	3	5	16
				F	24
3	Base	283.75	4	G	25
				M	25

TABLE 8

ARIZONA PUBLIC SERVICE COMPANY
FOUR CORNERS STATION

CORROSION DATA

Boiler No.	Firing Cond.	Exposure Hrs	Probe No.	Coupon No.	Corrosion MPY
4	Low NO_x	255.25	1	T	61
				U	160
4	Low NO_x	255.5	2	R	25
				S	24
5	Base	273.5	3	P	157
				Q	59
5	Base	273.75	4	N	45
				O	59

TABLE 9

ALABAMA POWER COMPANY
BARRY STATION

CORROSION DATA
BASE OPERATION

Boiler No.	Firing Cond.	Exposure Hrs	Probe No.	Coupon No.	Corrosion MPY
4	Base	295.5	1	VV	34
				W	24
4	Base	295.5	2	X	17
				&	18
4	Base	295.75	3	15	11
				16	13
4	Base	295.25	4	17	16
				18	17

TABLE 10

ALABAMA POWER COMPANY
BARRY STATION

"LOW NO$_x$" OPERATION

Boiler No.	Firing Cond.	Exposure Hrs	Probe No.	Coupon No.	Corrosion MPY
4	Low NO$_x$	282.75	1*	14	32
				B	26
4	Low NO$_x$	282	2*	K	41
				M	52
4	Low NO$_x$	281.25	3**	N	77
				P	87
4	Low NO$_x$	281.75	4**	Q	13
				Z	18

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* Eleven feet below lower burners in side walls (slag blowers No. 3 and 11).

** Eleven feet above top burners in side walls (slag blowers No. 18 and 26).

Total weight loss data were converted to corrosion rates on a mils per year basis, using the combined inner and outer coupon areas, coupon material density, and exposure time. Wastage was found to have occurred on the internal surfaces of some of the coupons, possibly because of the oxidation of the hot metal by the cooling air. Attempts were made to determine "internal" and "external" corrosion rates by selective cleaning and weight loss determinations, but the results were found to be more consistent and reliable on an overall basis.

3.3.1 Georgia Power Company

The first furnace corrosion probe tests were conducted on boilers numbers 3 and 4 at the Harllee Branch Station of the Georgia Power Company. Boiler No. 3, as indicated in Table 6, was fired at "low NO_x" conditions while boiler No. 4, a sister-unit was used to obtain baseline data under normal operation. All probes were inserted through slag blower ports extending through the windbox at an elevation about 8 ft. above the top burners. Exposure of the probes was maintained for approximately 300 hours at these firing conditions, after which the corrosion coupons were removed and processed in the laboratory.

Corrosion rate determinations for the Georgia Power Company tests are tabulated in Table 6. It may be noted that the corrosion rates on coupons No. 6 and 8 exposed to "low NO_x" firing conditions are the same as those obtained on coupons No. 10 and 12, exposed to normal firing. Rates on "low NO_x" coupons Nos. 7 & 9, however, are considerably higher than those obtained under normal operation. Analyses of these data, however, indicate that the differences are not statistically significant. Since this one was our first furnace corrosion tests conducted, a possible explanation for the higher corrosion rates obtained on the same probe, i.e., coupons No. 6, 7, and 8, 9, is that metal temperatures on adjacent coupons may not have been balanced, and potentially could have been higher on those coupons showing higher corrosion rates. This could also explain some of the differences in corrosion rates between "low NO_x" and baseline operation.

It is concluded that there are no significant differences between the corrosion rates under "low NO_x" firing conditions in Harllee Branch boiler No. 3, and those in No. 4 operated under normal firing conditions, even though somewhat higher corrosion rates were measured on two coupons on probes exposed to "low NO_x" conditions.

3.3.2 Utah Power & Light Company

Four corrosion probes were installed in inspection doors on the front wall of boiler No. 3 at the Naughton Station of the Utah Power & Light Company, as indicated in Figure 4. The objective was to obtain both "baseline" and "low NO_x" corrosion data at the same time, under "low NO_x" firing conditions. This attempt was based on the high O_2 levels expected to prevail at the upper inspection doors, where probes No. 1 & 2 were located. Reducing atmospheres were expected to prevail in the vicinity of probes No. 3 & 4 located in the middle of the burner array. However, potential furnace slagging conditions and critical system load conditions prevented sustained operation at "low NO_x" conditions on this unit. Accordingly, the corrosion probes were exposed to normal operating conditions for a period of 300 hours. Although the data obtained on these probes do not permit comparison of corrosion rates at "low NO_x" and baseline conditions for this unit, they do provide information on baseline corrosion rates of value for comparison with similar data obtained on other boilers.

Corrosion rates obtained at the Naughton Station are listed in Table 7. It may be seen that the corrosion rates on all coupons are reasonably consistent, ranging between 16 and 65 mils/yr., with the exception of probe No. 1 which had a higher rate and is out of line with the others. Corrosion rates on probes Nos. 1 & 2, ranging between 43 and 124 mils/yr., are higher than those on probes No. 3 & 4 (16-25 mils/yr.). Measured oxygen levels at the latter probes were lower at this location than that prevailing at probes No. 1 & 2. These data, therefore, provide some indication that corrosion rates at lower oxygen levels may be less than that of coupons exposed to higher oxygen atmospheres.

It is concluded that the Naughton data are indicative of accelerated corrosion rates prevailing under normal firing conditions on tangentially fired boilers. These data also indicate that corrosion rates may be lower on probes exposed to lower oxygen level environments.

3.3.3 Arizona Public Service Company

Two corrosion probes each were installed in Boiler No. 4, at the Four Corners Station, the "low NO_x" test unit, and Boiler No. 5, the "base" operation unit, which is a duplicate of Boiler No. 4. The probes were inserted through the slag blower ports which extend through the windbox of these horizontally opposed fired units. Corrosion data obtained are shown in Table 8.

Probes No. 1 & 2 in boiler No. 4 were exposed for about 255 hours, essentially at "low NO_x" firing conditions. However, there were periods during this time span when the unit was not operated entirely at the prescribed "low NO_x" conditions, due to mill losses, upsets in plant operation, and other problems. For the major part of the time, though, the probes were exposed under "low NO_x" firing conditions. It can be seen from Table 8 that corrosion rates range between 24 and 160 mils/yr. on the coupons mounted on probes No. 1 & 2 exposed to "low NO_x" conditions. These values compare to a range of 45 to 157 mils/yr. obtained on the "baseline" probes (No. 3 & 4) which were exposed to normal firing conditions for about 274 hours. The lowest corrosion rates, 24 & 25 mils/yr., were experienced on coupons R & S mounted on probe No. 2 exposed to "low NO_x" firing. The lowest rate on the base operation probes was 45 mils/yr., on coupon "N". Comparison of the corrosion rates on the remaining coupons shows that there are no significant differences between the coupons exposed under "low NO_x" firing and those exposed under normal firing conditions. In fact, the rates are remarkably consistent, and practically equal.

From the corrosion data obtained at the Four Corners Station, it is concluded that corrosion rates are essentially the same under "low NO_x" and baseline firing conditions. Also, based on these limited data, there is an indication that corrosion rates under "low NO_x" conditions may even be somewhat lower than under "baseline" operating conditions.

Four corrosion probes were installed on boiler No. 4 at the Barry Station of the Alabama Power Company and exposed for about 282 hours under "low NO_x" operating conditions. The probes were removed at the conclusion of this test, refitted with new coupons and re-inserted in the same boiler and locations and exposed for about 282 hours under normal firing conditions. Locations of the probes in the boiler are detailed in Figure 4 and corrosion data are tabulated in Table 9 for baseline operation, and Table 10 for "low NO_x" firing.

Comparing Tables 9 and 10 it will be noted that coupon corrosion rates for "low NO_x" operation are higher than for a baseline operation. The "low NO_x" corrosion rates are significantly higher at about the one per cent probability level. The corrosion test in boiler No. 4 was probably the most reliable test made under "low NO_x" conditions to date. Load and "low NO_x" firing conditions during the test period were maintained steadier than in other tests. Also, except for some minor variations; the coupon temperatures were maintained more consistently at the 875°F set point than in other tests. In contrast, even though coupon temperatures were maintained at a reasonably consistent level, boiler load conditions under the base operation test period varied widely. This problem was primarily due to pulverizer failures which required removing pulverizers from service. When the test was first started four pulverizers were in service. Mills were progressively dropped off until only two were in service for a good portion of the test period. This factor could have a significant effect on the corrosion rates shown in Table 9 for baseline operation.

Referring to Table 9, it should be noted that coupon corrosion rates on probes 1 & 2 installed below the lower burners averaged 24 mils per yr. compared to an average of 14 mils per yr. for probes Nos. 3 & 4, located above the top burners. Under "low NO_x" firing conditions (Table 10) the reverse occurred; average corrosion of coupons on probes 1 & 2 was 38 mils per yr. compared to 49 mils per yr. for probes No. 3 & 4. This difference could be explained by the less intense firing conditions prevailing in the area of probes No. 3 & 4 during the baseline test due to firing the lower burners only. However, it is doubtful that this reversal in corrosion rates between the upper and lower probes under the different firing conditions is truly significant.

Based on the data of Tables 9 and 10 for the Alabama Power Company tests, it is concluded that corrosion rates under "low NO_x" firing conditions are significantly (but not catastrophically) higher than those measured under baseline operating conditions. Furthermore, corrosion rates on probes at different locations in the boiler may be different, depending on whether the boiler is fired normally, or with "low NO_x" firing modifications, and also, with the location of the flame zone in the furnace.

4. DISCUSSION

In this section of the paper, the overall correlations of the NO_x emission data, and the significance of particulate emission measurements and accelerated corrosion tests are discussed.

4.1 Gaseous Emission Measurements

Tables 11 and 12 summarize the NO_x emission levels measured from wall-fired and tangentially-fired (plus a turbo-furnace) boilers, respectively. Inspection of Table 11 reveals that all of the wall-fired boilers have baseline NO_x emission levels greater than the current federal standard of 0.7 pounds $NO_x/10^6$ BTU or 1.26 grams $NO_x/10^6$ cal for new units. "Low NO_x" operation at full load reduced NO_x emission levels by 25 to 47% from baseline levels, and only Crist No. 6 boiler was unable to meet the federal NO_x standard for new boilers. "Low NO_x" operation at reduced load resulted in 40 to 54% NO_x emission reductions from baseline operation. The high CO emission levels shown under "low NO_x" operations were generally reduced to acceptable levels during the sustained test periods.

Examination of Table 12 reveals that baseline NO_x emission levels from tangentially fired boilers are lower than baseline NO_x emission levels from wall fired boilers. (The turbo-furnace boiler was tested at 370 MW compared to design full load of 450 MW, and hence, additional testing is needed to measure baseline, full load NO_x emission levels.) "Low NO_x" staged firing operation with 15-20% load reduction enabled these boilers to decrease NO_x below the federal NO_x emission standard for new coal fired boilers by a large margin, while each of these boilers demonstrated the capability of meeting such standards at full load with low excess air operation during the short-period tests. "Low NO_x" operation with further load reduction resulted in NO_x emission reductions of 55 to 64% compared to full load, baseline emission rates.

As noted in Section 3, it should be recognized that these results were obtained during short-term test periods and that long-term testing is needed to study slagging, corrosion and other operating conditions. It is expected that slagging problems in some boilers can be largely overcome by increasing slag blower steam pressures, increasing the use of slag blowers and perhaps the addition of slag blowers at troublesome locations. Lower NO_x emissions would also be expected in many boilers from improved furnace maintenance, so that air-to-fuel ratios are as uniform as practical across the furnace. Research at extremely low % stoichiometric air to the active burners (less than 75%) with staged firing may yield significantly improved NO_x emission rates with decreased slagging, because of lower temperatures. Also, the addition of "NO-ports" would probably allow most boilers to reduce NO_x emissions significantly during full-load operation with all burners firing coal.

TABLE 11

SUMMARY OF NO_x EMISSION LEVELS FROM WALL FIRED BOILERS

BOILER	OPERATING MODE (GROSS LOAD-MW)	% O_2	NO_x EMISSIONS PPM ($0\%\ O_2$)	NO_x EMISSIONS LBS/ 10^6 BTU	NO_x EMISSIONS GRAMS/ 10^6 BTU	PPM CO*** ($0\%\ O_2$)
1. WIDOWS	BASE (125)	3.0	750	0.84	1.50	300
CREEK No. 6	"LOW NO_x"* (125)	1.7	395	0.44	0.79	1140
(FW)	"LOW NO_x"** (100)	2.7	346	0.39	0.69	980
2. CRIST	BASE (320)	3.6	990	1.10	1.98	26
NO. 6	"LOW NO_x"* (320)	2.6	740	0.82	1.48	580
(FW)	"LOW NO_x"** (272)	3.1	600	0.67	1.20	310
3. HARLLEE	BASE (480)	3.5	870	0.97	1.75	24
BRANCH NO. 3	"LOW NO_x"* (478)	1.7	575	0.64	1.15	61
(HO)	"LOW NO_x"** (400)	1.3	390	0.43	0.78	1080
4. FOUR	BASE (800)	5.0	1070	1.19	2.15	23
CORNERS NO. 4	"LOW NO_x"* (800)	3.2	570	0.64	1.15	200
(HO)	"LOW NO_x"** (600)	3.0	525	0.59	1.05	33

* "LOW NO_x" CONDITIONS SELECTED FOR SUSTAINED RUN, AT FULL LOAD.

** "LOW NO_x" CONDITIONS AT REDUCED LOAD.

*** LOWER CO LEVELS MEASURED UNDER SUSTAINED STEADY-STATE CONDITION IN REPEAT RUNS.

TABLE 12

SUMMARY OF NO_x EMISSION LEVELS FROM TANGENTIALLY FIRED BOILERS

BOILER	OPERATING MODE (GROSS LOAD-MW)	% O_2	NO_x EMISSIONS			PPM CO (0% O_2)
			PPM (0% O_2)	LBS/ 10^6 BTU	GRAMS/ 10^6 CAL.	
5. NAUGHTON NO. 3	BASE (328)	3.9	600	0.67	1.20	35
	"LOW NO_x"* (256)	2.9	230	0.26	0.46	440
	"LOW NO_x"** (200)	3.2	214	0.24	0.43	65
6. BARRY NO. 4	BASE (348)	4.6	485	0.54	0.97	28
	"LOW NO_x"* (285)	3.3	285	0.32	0.57	68
	"LOW NO_x"** (185)	3.7	220	0.24	0.44	328
7. BARRY NO. 3	BASE (250)	3.1	480	0.54	0.96	71
	"LOW NO_x"* (250)	1.3	360	0.40	0.72	116
TURBO-FURNACE BOILER						
8. BIG BEND NO. 2	BASE (370)	2.8	715	0.79	1.43	30
	"LOW NO_x" * (300)	1.8	400	0.44	0.80	80
	"LOW NO_x"** (230)	3.5	365	0.41	0.73	260

* "LOW NO_x" CONDITIONS SELECTED FOR SUSTAINED RUN.

** "LOW NO_x" CONDITIONS WITH FURTHER LOAD REDUCTION.

Figures 18, 19 and 20 have been prepared to show the overall correlations of NO_x emissions vs % stoichiometric air, and gross load per furnace firing wall for the eight coal fired boilers tested to date in this program.

Figure 18 is a plot of "normalized" NO_x emissions, expressed as a % of baseline NO_x emissions (full load and 20% excess air) vs. % overall stoichiometric air (or % stoichiometric air to active burners) under normal firing conditions. The solid lines shown for each boiler are based on least-squares, linear regression analysis of all test runs made under normal (all burners firing coal) full load firing conditions. With the exception of the turbo-furnace boiler, all of these regression show very good agreement with about a 20% reduction in NO_x at 110% vs. 120% stoichiometric air. The three tangentially fired boilers show especially good agreement in this significant correlation of NO_x emission levels with excess air levels.

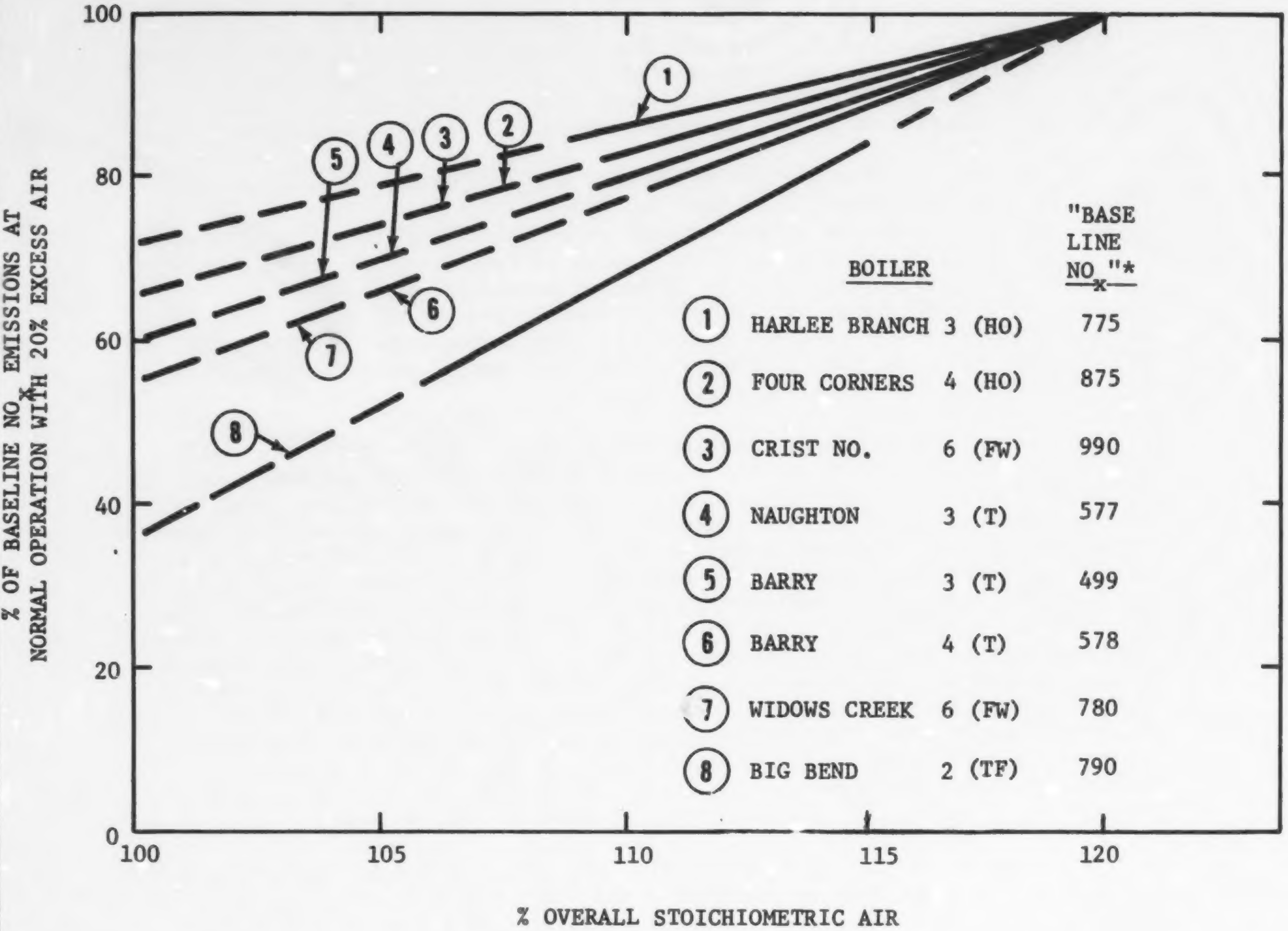
Figure 19 is a plot of normalized NO_x emissions expressed as a % of baseline NO_x emissions (full load and 20% overall excess air) vs. % stoichiometric air to the active burners under modified firing conditions. Thus, the ordinates are identical in Figures 18 and 19. However, the least squares regression lines of Figure C2 do not necessarily pass through the 100% normalized NO_x point at 120% stoichiometric air to the active burners, as they must, by definition, in Figure 18. Regression lines for Barry No. 3 and Big Bend No. 7 do pass through the 100%/120% point, since staged firing was not employed for those boilers.

Figure 19 indicates the importance of low excess air firing on NO_x emissions, as well as the further benefits of staged firing and additional firing modifications. The opposed wall fired boilers Harllee Branch No. 3 and Four Corners No. 4 boilers showed excellent agreement, as would be expected, since both of them represent modern design practices of Babcock and Wilcox with their cell-type burners. The tangentially fired boilers, Barry No. 4 and Naughton No. 3, that employed staged firing showed similar trends, with Naughton No. 4 giving the lower NO_x emissions because it was tested at lower % stoichiometric air levels. Widows Creek No. 6 boiler showed consistently larger reductions with normalized NO_x than Crist No. 6 boiler at the same stoichiometric levels. Boiler parameters such as size, coal type fired, pulverizer conditions, and other design and operating variables undoubtedly contribute to the differences found. We are in the course of examining whether the correlation methods of Figures 18 and 19 are applicable to oil and gas fired boiler NO_x emission data obtained in earlier work.

Figure 20 is a plot of baseline NO_x emission levels (ppm at 0% O_2, dry basis) vs. gross load per furnace firing wall for the 8 boilers under baseline operation. The dashed line is calculated from the 1971 "Systematic Field Study" (4). There appears to be a good correlation on this basis. However, we expect to find an improvement by combining the results of all 15 coal fired boilers tested to date. The regression intercept of 478 ppm NO_x at zero load corresponds to about 25% conversion of the average fuel nitrogen content of 1.3 wt% of the coals fired in this study. This observation is a strong indication of the significant contribution of bound fuel nitrogen to NO_x emissions from coal fired boilers. Substoichiometric air supply to the active burners is expected to reduce both the fixation of molecular N_2, and the oxidation of fuel nitrogen, based on independent laboratory data.

FIGURE 18

EFFECT OF EXCESS AIR ON NO_x
UNDER NORMAL FIRING CONDITIONS



	BOILER		"BASE LINE NO_x"*
①	HARLEE BRANCH	3 (HO)	775
②	FOUR CORNERS	4 (HO)	875
③	CRIST NO.	6 (FW)	990
④	NAUGHTON	3 (T)	577
⑤	BARRY	3 (T)	499
⑥	BARRY	4 (T)	578
⑦	WIDOWS CREEK	6 (FW)	780
⑧	BIG BEND	2 (TF)	790

* NO_x (PPM, AT 0% O_2, DRY BASIS) UNDER NORMAL FIRING WITH 120% STOICHIOMETRIC AIR.

FIGURE 19

EFFECT OF EXCESS AIR ON NO_x
UNDER MODIFIED FIRING CONDITIONS

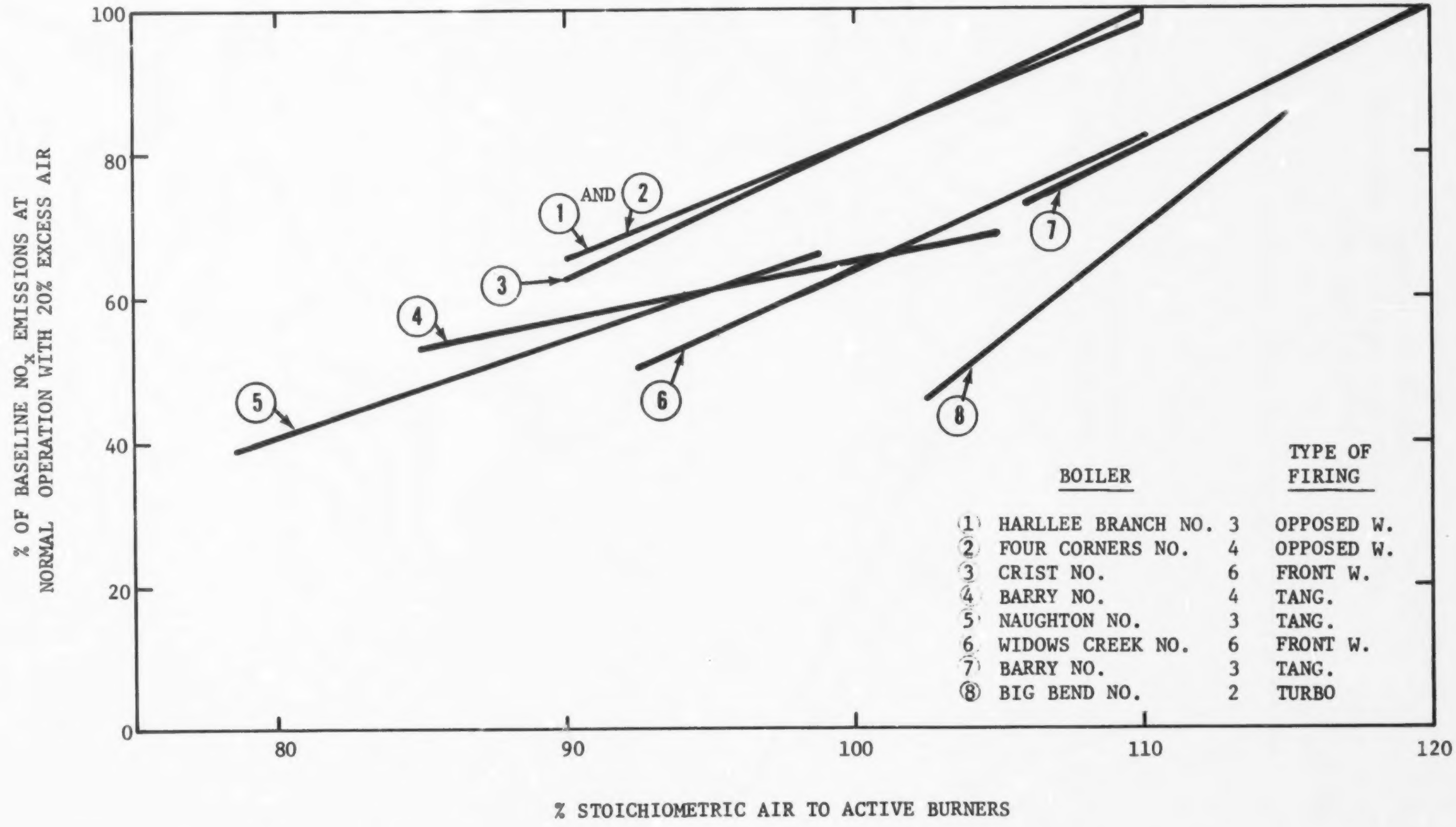
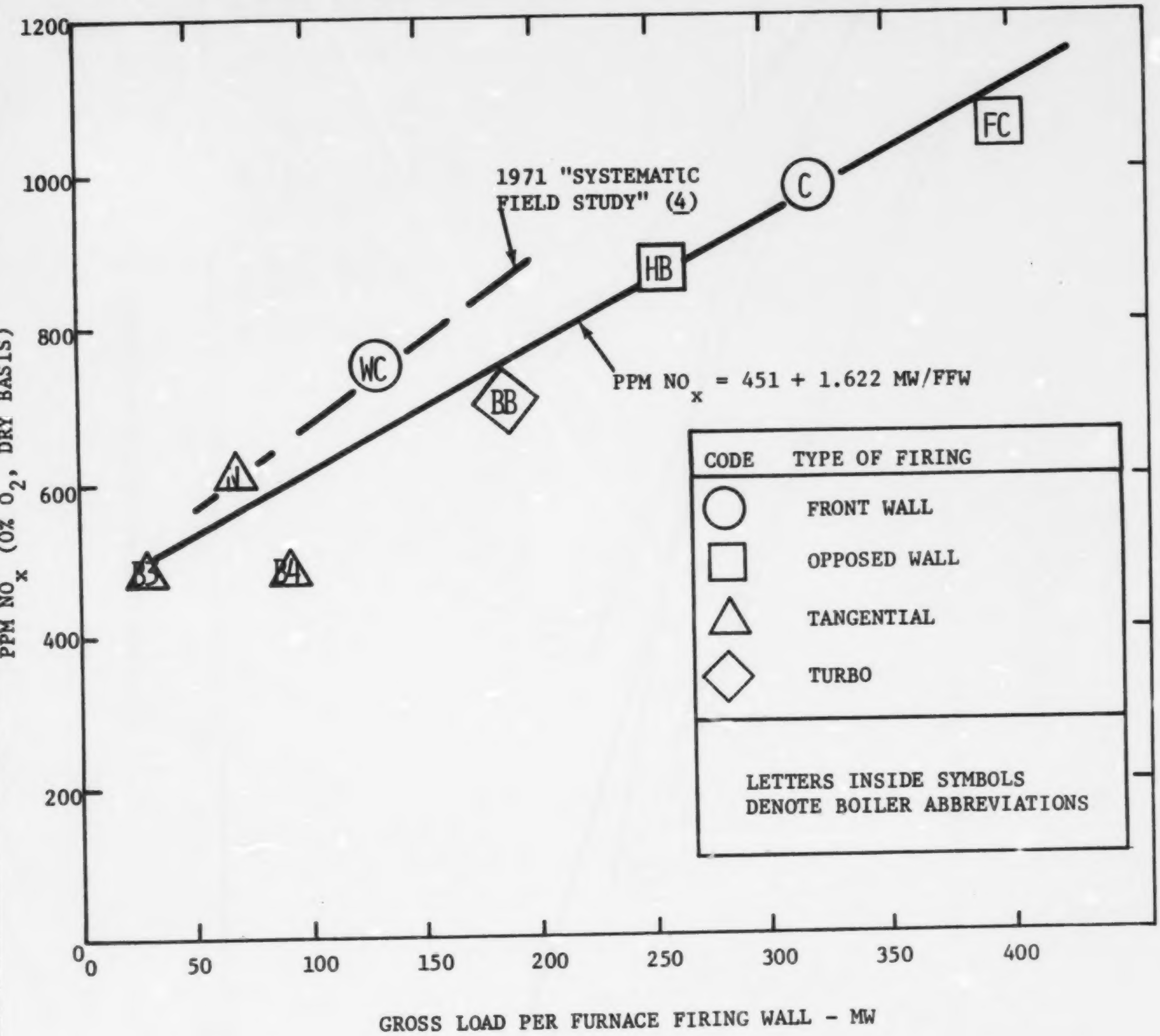


FIGURE 20

COAL FIRED BOILERS
UNCONTROLLED NO_x EMISSIONS VS GROSS LOAD PER FURNACE FIRING WALL



4.2 Particulate Measurements

Obtaining good particulate data is a difficult, time consuming task. One must be involved in the actual test work to appreciate the difficulties encountered. C. A. Gallaer discusses this matter in detail in his paper on the testing of large precipitators (7).

In this program, four Research Appliance Company EPA-type particulate sampling trains were used. The design of this equipment is very good, but many difficulties occur in operation, as is inherent to particulate testing. Care must be taken to assure that the probes and tests boxes are at specified temperatures. Even then, especially in cold weather, moisture in the flue gases condensing in the apparatus can quickly plug filters and abort the test. Tests for leaks in each train prior to testing is also needed if meaningful data are to be obtained. Plugging of sampling probes on occasion also occurs, and can present difficulties in boilers with high dust loadings.

The facilities to be tested are another source of numerous problems. Rarely is a boiler encountered with convenient testing facilities. Sample test ports are usually located too close to bends in the flue ducts where particulate concentrations, due to centrifugal action, cannot possibly be uniform. Interferences of the probes with supports inside the flue ducts and of the test apparatus with other obstructions outside the boiler, near test locations, all contribute to the difficulty in running particulate loading tests. Last but not least, the EPA-type test train is built for horizontal probing, while most boiler test locations require vertical probing. Our equipment has been modified for vertical probing, so that usually the construction of scaffolding is necessary for access to the equipment.

Despite the problems of conducting particulate tests, the results obtained on this program, summarized in Table 5, are internally consistent and appear to be reliable within the limitations of this type of testing. The objective of our work was to develop information on potential "side effects" of "low NO_x" firing techniques on total quantities and the carbon content of the particulates generated. It is recognized that strict adherence to EPA procedures was not always possible especially with regard to the number of sampling ports and traverse points, but the same procedures were used for under both baseline and "low NO_x" conditions. Therefore, the differences shown by the results on particulate emissions and particulate carbon content in Table 5 should be quite reliable.

Not unexpectedly, some "side effects" did develop with "low NO_x" firing. Total quantities of particulate tend to increase but not signicantly and the consequences appear to be relatively minor. This trend would have an adverse effect on the required collection efficiency of electrostatic precipitators to meet present Federal emission standards, but the increases in efficiency indicated by these limited tests appear to be quite small.

Another "side effect" of "low NO_x" operation is that on carbon losses. Carbon content of the particulates with "low NOx" operation, according to the data, increase significantly for front wall and horizontally opposed fired boilers. The data are quite scattered, and these increases do not appear to be directly related to the change in emissions with "low NO_x" firing techniques, or other boiler operating variables. Comparative performance calculations have not yet been completed for assessing the magnitude of such adverse effects of staged firing with coal. It is possible, however, that this debit may be offset by improved boiler efficiency due to the lower excess air operation at "low NOx" conditions. Surprisingly, there is some evidence that "low NOx" firing techniques for tangentially fired boilers decrease carbon losses significantly. If this finding can be substantiated for other tangentially fired boilers, a net credit may be applied to "low NO_x" operation of these units. It also appears that "low NO_x" firing may decrease carbon losses for boilers fired with western coals. Such improvements, however, would not be substantial since unburned combustible losses with the easy-to-burn Western coals are already low.

More data are needed on all types of boilers to substantiate these findings. It is important to note, however, that no major adverse "side effects" appear to result from "low NO_x" firing with regard to particulate emissions.

4.3 Furnace Corrosion Testing

Corrosion of boiler furnace sidewall tubes was experienced in the early days of the development of pulverized coal firing. Considerable effort was expended at the time in the field, to find solutions to the problem; and in the laboratory, to determine the corrosion mechanism. Eventually, simple solutions were found by increasing the level of excess air and taking steps to avoid impingement of ash particles on sidewall tubes. Apparently, not much information had been published, probably because a practical solution to the problem was available.

Recent regulations requiring reduction of nitrogen oxide emissions have led to the reduction of excess air levels in firing boilers, as one of the techniques to achieve lower emission levels. This approach has resulted in considerable speculation and apprehension that furnace sidewall tube corrosion problems will again be encountered. Quite naturally, boiler owners are reluctant to subject their units to long term tests to determine potential corrosion problems without some assurance that risks are not grave.

For the above reasons, part of the current program was devoted to obtaining "measurable" corrosion rates on probes exposed to actual furnace conditions. The objective of this effort was to obtain data on potential effects of "low NO_x" firing conditions on furnace wall tube corrosion rates. The approach used in obtaining these data was to deliberately accelerate corrosion on coupons exposed to temperatures in excess of normal tube metal temperatures. It was decided that exposure for 300 hours at 875°F in susceptible furnace areas would be sufficient to show major differences in corrosion rates between coupons exposed to "low NO_x" firing conditions and those exposed under normal conditions.

Although there was some scatter in the data obtained, most of the information was quite consistent. A major finding was that no major differences in corrosion rates were observed for coupons exposed to "low NO_x" conditions compared to those subjected to normal operation. In fact, for some probes, the corrosion rates were found to be even lower than for "low NO_x" exposure.

Since corrosion was deliberately accelerated in the corrosion probe test work in order to develop "measurable" corrosion rates in a short time period, measured rates, as expected, are much higher than normal wastage experienced on actual furnace wall tubes. In future tests, coupons will not be pickled to remove oxide coatings, and coupon temperatures will be reduced to bring corrosion rates more nearly in line with actual tube wastage.

Much more data are obviously required to resolve the question of furnace tube corrosion under "low NO_x" firing conditions. The limited data obtained in this program should be helpful in providing evidence that furnace tube corrosion may not necessarily be a severe "side effect" of low NO_x firing. Long term "low NO_x" tests using corrosion probes and the simultaneous development of actual furnace wall tube corrosion rates by "before" and "after" ultrasonic thickness determinations are recommended for future studies.

5. CONCLUSIONS

The results obtained in this study to date show that modifications of the combustion operation have a good potential for reducing NO_x emissions from coal-fired utility boilers without undesirable side-effects. Lowering the level of excess air and staging the firing of burners resulted in significant reductions in NO_x, averaging about 40-50% for the boilers tested in the short-term phase of our test programs. The degree of reduction, as well as the baseline NO_x level varied with the type and size of the coal-fired boiler tested, and presumably also with coal type. In general, tangentially fired boilers were found to produce the lowest NO_x emissions, both under baseline and modified firing conditions. However, the burner firing patterns could be changed for wall-fired units without load reduction, resulting in decreases in NO_x emissions of as much as 50% under full load conditions. There is too little information on the one turbo-furnace unit tested to draw firm conclusions on the effect of this type of boiler design on NO_x emissions.

The NO_x emission data were successfully correlated with per cent stoichiometric air supplied to the burners, for both normal and staged firing patterns. These correlations show the strong effect of firing coal burners under net reducing conditions on decreasing NO_x emissions. One anticipates even further improvements if boiler operability problems, particularly slagging and corrosion can be overcome. In combination with the correlation of baseline NO_x emissions per megawatts generated (or firing rate) per "equivalent firing wall", these correlations of the present study should be useful for predicting the level of NO_x emitted under normal and staged firing conditions. (Similar correlations may be developed for gas and oil fired boilers, based on our data obtained in previous studies.) The correlations suggest that on the average, about 25% of the chemically bound nitrogen in coal is converted to NO_x. Thus, fuel nitrogen is an important factor in NO_x emissions from coal-fired utility boilers.

Particulate loading and carbon in fly-ash measurements made under baseline and staged firing, "low NO_x" conditions, appear to show some increase for both of these parameters under "low NO_x" conditions, but in some cases the opposite behavior has been observed. No extreme differences in flue gas particulate loadings and in the carbon content of the fly-ash have been found during our boiler tests.

Under the "low NO_x" firing conditions defined during the short-term optimization tests, 300-hour accelerated corrosion tests have been conducted on several boilers in this program. Comparison of the accelerated corrosion rates measured under "low NO_x" and those measured under normal firing conditions does not reveal major differences. Therefore, it is recommended that long-term corrosion tests should be conducted with staged firing of coal on carefully selected, representative boilers.

Further test work is needed to optimize and demonstrate the promising NO_x control technology based on the results of this work. As mentioned above, particular attention should be paid to long term corrosion testing. In addition, boilers fired with different coal types should be tested to define the limitations imposed at present by slagging problems on the level of substoichiometric air that can be supplied to the active burners. Based on such information, techniques for minimizing slagging problems should be developed. Careful control of boiler operation in additional tests should allow the optimization of NO_x emission control for coal-fired utility boilers.

6. REFERENCES

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7. ACKNOWLEDGMENTS

This study was conducted under the sponsorship of the Environmental Protection Agency, pursuant to Contract No. 68-02-0227. We wish to acknowledge the active participation of Mr. R. E. Hall, the EPA Project Officer, in planning the test program and providing coordination with boiler manufacturers and operators. The cooperation and advice of major U.S. utility boiler manufacturers, Babcock & Wilcox, Combustion Engineering, Inc., Foster Wheeler Corp., and Riley-Stoker were essential to planning, and scheduling these tests. Our thanks are due to the electric utility concerns for their voluntary participation in making their boilers available for testing. These boiler operators were the Alabama Power Company, Arizona Public Service, Georgia Power Company, Gulf Power Company, Tampa Electric Company, Tennessee Valley Authority, and Utah Power and Light Company. Also, the able assistance of Messrs. L. W. Blanken, R. W. Schroeder and A. J. Smith in performing these test programs is acknowledged.

APPENDIX

EMISSION FIELD PROGRAM
EPA/OAP Contract No. 68-02-0227
Esso Research and Engineering Company

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Recommendations for Selection Criteria for Field Testing Coal Fired Boilers

I. Design Factors

1. Size: 150 to 1200 MW max. cont. rating, representative of current and future design practices of boiler manufacturers.
2. Type of firing: tangential, horizontally opposed, front wall, and cyclone*.
3. Furnace loading.
4. Furnace design: number of furnaces and/or division walls.
5. Furnace bottom design: wet or dry.
6. Burner configuration: size, number, and spacing.
7. Draft system: pressurized or balanced.
8. Special features available for NO_x control: NO-ports, flue gas recirculation into flame zone**. Control of air flows (e.g., primary/secondary).

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* Cyclone boiler to be tested only if combustion modification flexibility available.

** Or possibility of diverting existing FGR (now used for steam temperature control) into flame zone.

II. Boiler Operating Flexibility

1. Excess air: 5% to 30%. LEA operation (< 15% desirable for sustained operation).
2. Furnace load with all burners firing: 60% to 100% of MCR.
3. Staged firing: individual burners or rows of burners on air only; or biased firing of individual burners.

4. Flue gas recirculation: location of injection point and amount recirculated.
5. Windbox pressure: control from low to high, over full range of furnace load and excess air levels.
6. Combustion air preheat temperature variation.
7. Air register settings.
8. Fuels available: coal types, characteristic of major U.S. regions*.

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* Potential of mixed oil or gas/coal firing for stable staged combustion may be a desirable feature.

III. Boiler Measurement and Control Capability

1. Fuel rate: by furnace and pulverizer.
2. Air flow rate.
3. Steam temperature control: attemperation water, tilting burners*, secondary to primary air ratios.
4. Flue gas components monitored by operator: O_2, CO, combustibles, smoke.
5. Steam temperature and pressure, air and flue gas temperatures for steam side efficiency analysis.
6. Availability of furnace viewing ports for burner flames, slag build-up, etc. observation.
7. Availability of adequate fuel and flue gas sampling ports.

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* For tangential boilers only.

IV. Management Operating and Research Policy

1. Management support: make available necessary supervisory, technical and operating personnel for planning and testing.
2. Research-mindedness: willingness to exploit full boiler operating flexibility in test program.
3. Willingness to schedule load changes, calibrate boiler instruments, and bring boiler into proper operating condition for test program. Cooperation in coal sampling and analysis desirable.
4. Prior experience in emission test programs.

V. Logistics and Efficiency

Other factors being equal:

1. Select utility and/or station with more than one boiler meeting criteria.
2. Scheduled annual outage to suit test program schedule.
3. Increased program efficiency by minimizing travel costs.

PILOT AND FULL SCALE TESTS

PART II

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PILOT FIELD TEST PROGRAM TO STUDY METHODS FOR REDUCTION OF NO_X FORMATION IN TANGENTIALLY COAL FIRED STEAM GENERATING UNITS

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FOR PRESENTATION AT
PULVERIZED COAL COMBUSTION SEMINAR
JUNE 19 & 20,1973
SPONSORED BY THE COMBUSTION RESEARCH SECTION OF
THE ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK
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ABSTRACT

This paper describes the work completed on Phase I of a "Pilot Field Test Program to Study Methods for Reduction of NO_X Formation in Tangentially Coal Fired Steam Generating Units" performed under the sponsorship of the Office of Air Programs of the Environmental Protection Agency (Contract No. 62-02-0264). Phase I of the program consisted of selecting a suitable utility field steam generator to be modified for experimental studies to evaluate NO_X emissions control. This effort included the preparation of engineering drawings, a detailed preliminary test program, a cost estimate and detailed time schedule of the following program phases and a preliminary application economic study indicating the cost range of each combustion technique as applied to existing and new steam generators.

INTRODUCTION

The purpose of this program is to investigate various means for NO_x emission control as applied to coal fired utility steam generators. While current coal firing combustion and control technology have minimized smoke, CO, hydrocarbon and solid combustible emissions, proven techniques for the control of NO_x have not been fully developed and evaluated. Review of combustion process modifications which had been found effective in reducing NO_x emissions from oil and gas fired steam generators and recent staged combustion simulations with coal firing indicated that gas recirculation to the firing zone and/or staged combustion should be evaluated as commercially feasible methods of NO_x reduction. For these reasons a program was developed to evaluate the feasibility of these as well as other methods of NO_x control on a commercially sized pilot plant unit. This unit would be modified to incorporate the systems to be studied for evaluation of potential operating and control problems and the establishment of optimum methods for both transient and long term operation.

Phase I was conducted as part of a projected five phase program to identify, develop and recommend the most promising combustion modification techniques for control of NO_x, without objectionable increases in related pollutants, from tangentially coal fired utility steam generators. Phase I comprises the following tasks.

Task I - Selection of a suitable tangentially coal fired unit for emission control modification and testing.

Task II - Preparation of a detailed preliminary test program.

Task III - Preparation of engineering drawings, modification costs and time schedule.

Task IV - Estimate modification cost ranges for each combustion modification technique as applied to existing and new boilers.

DISCUSSION

Task I - UNIT SELECTION

To select a test unit, Combustion Engineering conducted a survey of utility companies using tangentially coal fired steam generators to determine their interest in participating in the NO_x control program. As a result of this survey, seven (7) utility companies expressed a desire to cooperate with CE in the program. These companies were subsequently reviewed to determine if they had within their generating systems units meeting the remaining criteria specified for the test unit.

Of several units found to be generally acceptable for the test program, Alabama Power Co., Barry Station Unit No. 1 was finally selected.

This unit is a natural circulation, balanced draft, steam generator, firing coal through four elevations of tilting tangential fuel nozzles. The superheat steam capacity at maximum continuous rating is 900,000 LBS/Hr main steam flow with a superheat outlet temperature and pressure of 1000 F and 1875 PSIG. Superheat and reheat temperatures are controlled by fuel nozzle tilt and spray desuperheating. A side elevation of this unit is shown in Figure 1.

The criteria upon which the selection was based are as follows.

1. The unit is representative of the tangentially coal fired steam generators currently designed by CE which facilitates the transfer of technology to existing and new boiler designs.

2. The unit, while representative of current utility boiler design, is small enough (125 MW) to minimize modification costs and permit a versatile experimental program. The control system installation can be coordinated with a planned outage for installation of a hot electrostatic precipitator. This precipitator would eliminate the need for additional dust removal equipment to protect the gas recirculation system fan.

3. The unit location permits testing of various coals without incurring additional coal transportation costs. Coals currently being burned at the station include both local Alabama and Illinois varieties. The station has existing facilities for receiving and handling of both rail and barge coal deliveries.

4. Alabama Power Company had expressed their willingness to cooperate and participate in this program by making the unit available for the required modifications and tests.

5. The results of a unit operating survey indicated that Barry 1 is acceptable for the planned experimental NO_X control study modifications. Briefly, unit operating flexibility, ash handling systems, fan capacities and normal operation NO_X levels were found to be acceptable for the purposes of this program. A plot of NO_X values versus excess air at various unit loadings is shown in Figure 2.

Task II - DETAILED TEST PROGRAMS

The detailed test programs were developed using a statistical program design approach. In this manner maximum program efficiency can be attained by obtaining the maximum informational output from each test.

Using this approach the individual variables considered for evaluation were first identified and then the minimum number of variable combinations which must be tested to properly evaluate each variable was established.

The individual variables identified for evaluation in one case were as follows:

Excess Air

Unit Loading

Air Preheat Temperature

Biased Firing

Gas Recirculation to:

a. Secondary Air Ducts

b. Coal Pulverizers

c. Combination of the above.

Overfire Air

Water Injection to the Firing Zone

For the second case, the variables to be evaluated were:

Excess Air

Unit Loading

Biased Firing

Overfire Air

The degree to which each process variable or modification would be applied and the process measurements necessary to evaluate unit performance follow.

Process Modifications

A. Overfire Air System

The overfire air system was designed to introduce a maximum of 20 percent of full load combustion air above the fuel admission nozzles through two additional compartments in each furnace corner located approximately eight feet above the fuel admission zone.

Overfire air can also be supplied to the furnace through the top two compartments of the existing windbox when the upper elevation of fuel nozzles is not in use. The overfire air nozzles will tilt +30° in the vertical plane independently of the main fuel and air nozzles. Independent dampers for each overfire air compartment will be provided as a means to study the influence of location and velocity of overfire air introduction.

B. Gas Recirculation System

The gas recirculation system was designed to recirculate flue gas to the secondary air duct and coal pulverizers either separately or in combination. The system would provide for a maximum of 40 percent recirculation at 80 percent unit loading and permit substituting gas recirculation for hot air to the coal pulverizers while introducing tempering air in the conventional manner. A gas recirculation temperature range from 300 to 650F would be possible by varying the weight ratio of flue gas taken from the air preheater gas inlet and outlet.

C. Air Preheat System

The preheated air temperature entering the secondary air duct can be varied by bypassing the air and/or gas side of the air preheaters to provide the maximum system flexibility.

D. Water Injection System

Water injection can be admitted into the furnace through two elevations of atomizing spray nozzles located between the top two and bottom two fuel nozzle elevations. A maximum injection rate of 50 pounds per million BTU fired can be used.

Process Variables

Excess air, unit load, and fuel and air distribution will be varied within the current limitations of the existing equipment. These limits were evaluated in the unit operating survey conducted in Task I.

Process Measurements

Operation of the unit as proposed in the experimental study will produce variations in unit operation and thermal performance. The following process measurements are required to properly assess the impact of these changes on new unit design and the retrofitting of existing units.

A. Furnace Absorption

Recirculating gases to the secondary air compartments and staging of combustion air will effect changes in both peak and average furnace waterwall temperatures and absorption rates. The waterwall crown temperatures and absorption rates must therefore be determined to evaluate the impact of variations in average and peak rates and absorption profiles on unit design.

B. Furnace Corrosion Probes

Unit operation with staged combustion air may result in local reducing atmospheres within the furnace envelope, resulting in accelerated waterwall corrosion rates. To assess the impact of this type of operation on waterwall wastage, furnace corrosion probes will be utilized.

C. Sensible Heat Leaving the Furnace

Variations in furnace heat absorption rates due to modifying the combustion process will result in increasing or decreasing the sensible heat leaving the furnace envelope and entering the superheat and reheat sections of the unit. To determine the sensible heat leaving the furnace, the exit gas temperature will be measured at the vertical furnace outlet plane using water cooled probes with radiation shielded thermocouples.

D. Superheat, Reheat and Economizer Section Absorptions

Variations in the gas temperature and gas flow leaving the furnace envelope and entering the convective sections of the unit will affect the total heat pickup of each section. To assess the impact of modified operation on superheat, reheat and economizer performance, the absorption rates for each section will be determined.

Variation in heat absorption rates may require resurfacing when retrofitting existing units for modified operation.

E. Air Heater Performance

Air and gas temperatures and gas side oxygen concentrations entering and leaving the air heater are required to calculate air heater performance, unit efficiency, heat losses and air and gas flow rates.

F. Fuel and Ash Analysis

During each test, a representative fuel sample must be obtained for later analysis. The fuel analyses are required to perform combustion calculations necessary to determine excess air levels and unit gas and air flow rates. Pulverized coal fineness samples will be obtained to determine the effect, if any, on furnace wall deposit characteristics, solid combustibles losses, NO_x levels and related emissions.

In addition, coal ash analyses are required to determine ash properties such as base/acid ratios and ash deformation, softening and fluid temperatures necessary for evaluating the furnace wall deposit characteristics of coal fuels. Furnace bottom ash, fly ash and coal pulverizer rejects analyses are also required to determine heat losses and material balances. Specific instrumentation and methods to be used in measuring these process variables and the flue gas emission constituents are defined in the detailed test plan.

Task III - ENGINEERING DRAWINGS, COST ESTIMATES AND DETAILED TIME SCHEDULE

Engineering Drawings

Arrangement drawings were completed showing necessary duct arrangements for the overfire air and gas recirculation systems, the overfire air register arrangements and control system interfaces with the existing unit. The general arrangement drawings for the ductwork indicate that the proposed control systems can be physically installed within the existing station without serious structural interferences.

The modification ductwork final locations were determined by an extensive design review and engineering field check of actual existing equipment configurations and locations.

Cost Estimates

The cost of fabricating, installing and testing the overfire air and gas recirculation systems were estimated both as a complete system and as individually installed systems. These estimates do not include additional fuel costs incurred during the test program as Alabama Power Company has agreed to assume these costs.

Detailed Time Schedules

Due to difficulties encountered in establishing when authorization to proceed with follow-on program phases would be received, it was not possible to finalize a detailed time schedule for installation of the control systems. Schedules based on elapsed time from start of contract were prepared and are shown in Figures 3 and 4. These schedules must be coordinated with a unit outage occurring in the tenth to twelfth program month. Such an outage is currently available in the spring of 1974.

Task IV - COMBUSTION TECHNIQUE APPLICATION COSTS

Application Study Results

Based on the cost estimates developed under Task III and Combustion Engineering, Inc.'s current knowledge, cost ranges were developed for applying the NO_X control techniques proposed in this program to new and existing unit designs. These cost ranges are illustrated in Figures 5 and 6.

Specifically, four possible methods of reducing NO_X emission levels from tangentially coal fired steam generators were evaluated and the cost trends for each method estimated for both new and existing units. The reduction methods considered included overfire air, gas recirculation to the secondary air ducts, gas recirculation to the coal pulverizer/primary air system and furnace water injection. The cost trends for these methods were projected over a unit size range of 125 to 750 MW.

The results of the study indicate that for any given unit size (450 MW chosen for an example comparison) the lowest cost method is found to be overfire air which results in a .14 to .50 $/KW additional unit cost for a new or existing unit respectively.

This method incurs no loss in unit efficiency or increased operating expenses.

Gas recirculation introduced either through the secondary air ducts or the coal pulverizers and primary transport air system results in higher equipment costs than overfire air and requires additional power for fan operation.

Water injection introduced into the fuel firing zone of the unit is attractive from the standpoint of low initial equipment costs, however, losses in unit efficiency resulting in increased fuel costs and significant water consumption make it the most expensive system to operate.

The use of either gas recirculation or water injection in existing units could result in a 10 to 20 percent decrease in load capability due to increased gas flow weights.

The following conclusions were drawn from this study.

1. The lowest cost method for reducing NO_x emission levels on new and existing units is the incorporation of an overfire air system. No additional operating costs are involved.

2. Gas recirculation either to the windbox or coal pulverizers is a promising control system but is significantly more costly than overfire air and requires additional fan power. In existing units, the necessity to reduce unit capacity to maintain acceptable gas velocities imposes an additional penalty.

3. Gas recirculation to the coal pulverizers would cost approximately 15 percent less than windbox gas recirculation, however, this method may require increased excess air to maintain adequate combustion.

4. Water injection has initially low equipment costs, but due to high operating costs resulting from losses in unit efficiency, is the least desirable of the systems evaluated. This system may also require reduced unit capacity.

5. In general, the cost of applying any of the control methods studied to an existing unit is approximately twice that of a new unit design.

Application Study Design

For the purpose of this study the following five modes of unit operation were chosen as potentially effective means for the reduction of NO_x emissions.

The quantities of overfire air, gas recirculation and water injection selected for the economic evaluation, while reasonable, do not necessarily represent commercially feasible operation or control methods which would be recommended by Combustion Engineering, Inc.

1. Introducing 20 percent of the total combustion air over the fuel firing zone as overfire air.

2. Introducing 30 percent flue gas recirculation through the secondary air ducts and windbox compartments.

3. Combining the 20 percent overfire air and 30 percent flue gas recirculation of 1 and 2.

4. Introducing 17 percent flue gas recirculation through the transport air/coal pulverizer system.

5. Introducing water injection into the fuel firing zone at a rate of 5 percent of total evaporation.

The economic comparisons of the five NO_x emission control methods were based on 1973 delivered and erected costs for the steam generators and associated equipment.

The cost estimates presented for the revision of existing units were based on studies performed on units within the 125 to 750 MW size range including those costs generated under Phase I, Task 3, for the Barry No. 1 unit. The cost estimates presented for incorporating control methods in new unit designs were based on Combustion Engineering experience and current practice for overfire air and gas recirculation systems.

As can be seen from Figures 5 and 6 the cost ranges for existing units vary more widely than new units. This is due mainly to variations in unit design and construction which either hinder or aid the installation of a given control system. For example, an overfire air system may be designed as a windbox extension unless existing structural requirements and obstructions necessitate installation of a more costly system including extensive ductwork and individual air injection ports. The same condition exists for water injection systems when the need to maintain unit capacity dictates changes in unit ducting. Except where noted, all system costs are estimated on a ±10 percent basis. The cost range of the combined overfire air and windbox gas recirculation system was arrived at as the sum of the cost ranges of the individual systems. The cost ranges presented for existing units do not include any changes to heating surface as these changes must be calculated on an individual unit basis. Due to variations in existing designs, heating surfaces may increase, decrease or remain unchanged for a given control method.

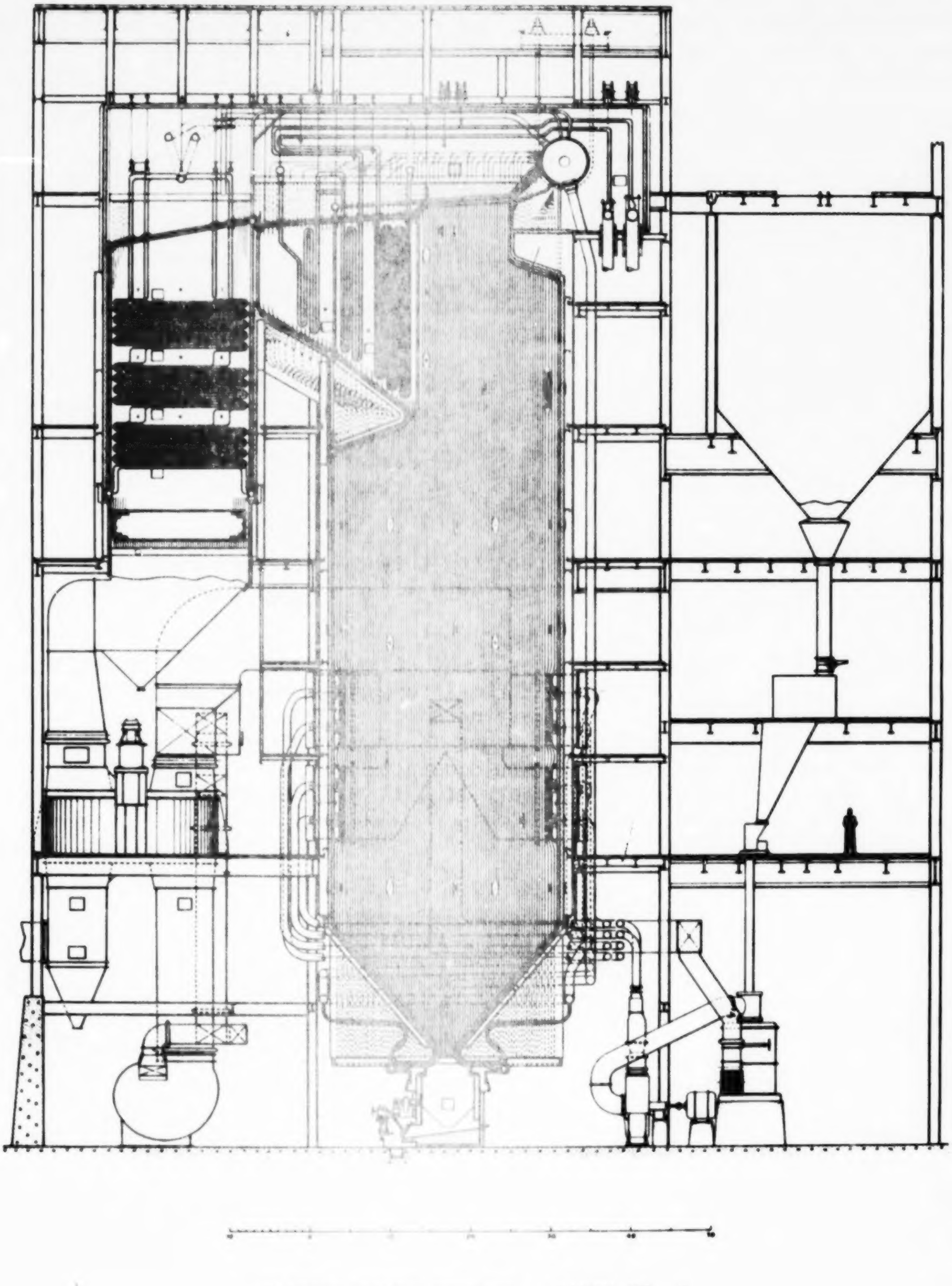
At approximately 600 MW, single cell fired furnaces reach a practical size limit and divided furnace designs are employed. Since a divided tangentially fired furnace has double the firing corners of a single cell furnace, the costs of windboxes and ducts increase significantly as shown on Figures 5 and 6. As shown, the costs of overfire air, windbox gas recirculation and windbox water injection increase from 30 to 50 percent.

In addition to the increased capital costs resulting from including an NO_X control system in a unit design, the increased unit operating costs must be considered. The increased annual operating costs were determined for a 100, 450 and 750 MW unit of new design and are shown in Table I. The equipment costs shown are determined from Figure 5. Using the 450 MW unit as an example at a rate of .14 $/KW results in an increase in unit capital cost of $63,000. The additional annual fixed charges, fuel and fan power costs for each of the five NO_X control methods studied and the criteria on which these costs are based are also listed on Table 1.

Again using the 450 MW unit as an example the study indicates that water injection is the most expensive system to operate at .332 mills/KWHR due primarily to increased fuel costs resulting from losses in unit efficiency. The least expensive control system to operate was overfire air at .004 mills/KWHR with gas recirculation either alone or in combination with overfire air ranging from .108 to .121 mills/KWHR.

To put these operating costs in perspective, they can be compared to "average" generating costs presented in Table 1 for various sizes of unmodified units.

Operating costs were developed only for a new unit design as it is possible to assume that design parameters would remain unchanged from a unit designed without NO_X controls. However for existing units, gas and air flow rate changes, increased draft losses and changes in unit load capabilities would vary to such a degree that each unit would have to be treated individually regardless of rating and costs would vary to such a degree that they would not be useful to a general study.



ALABAMA POWER COMPANY - BARRY NO. 1

ALABAMA POWER COMPANY - BARRY NO. 1

NO_X VS. PERCENT EXCESS AIR

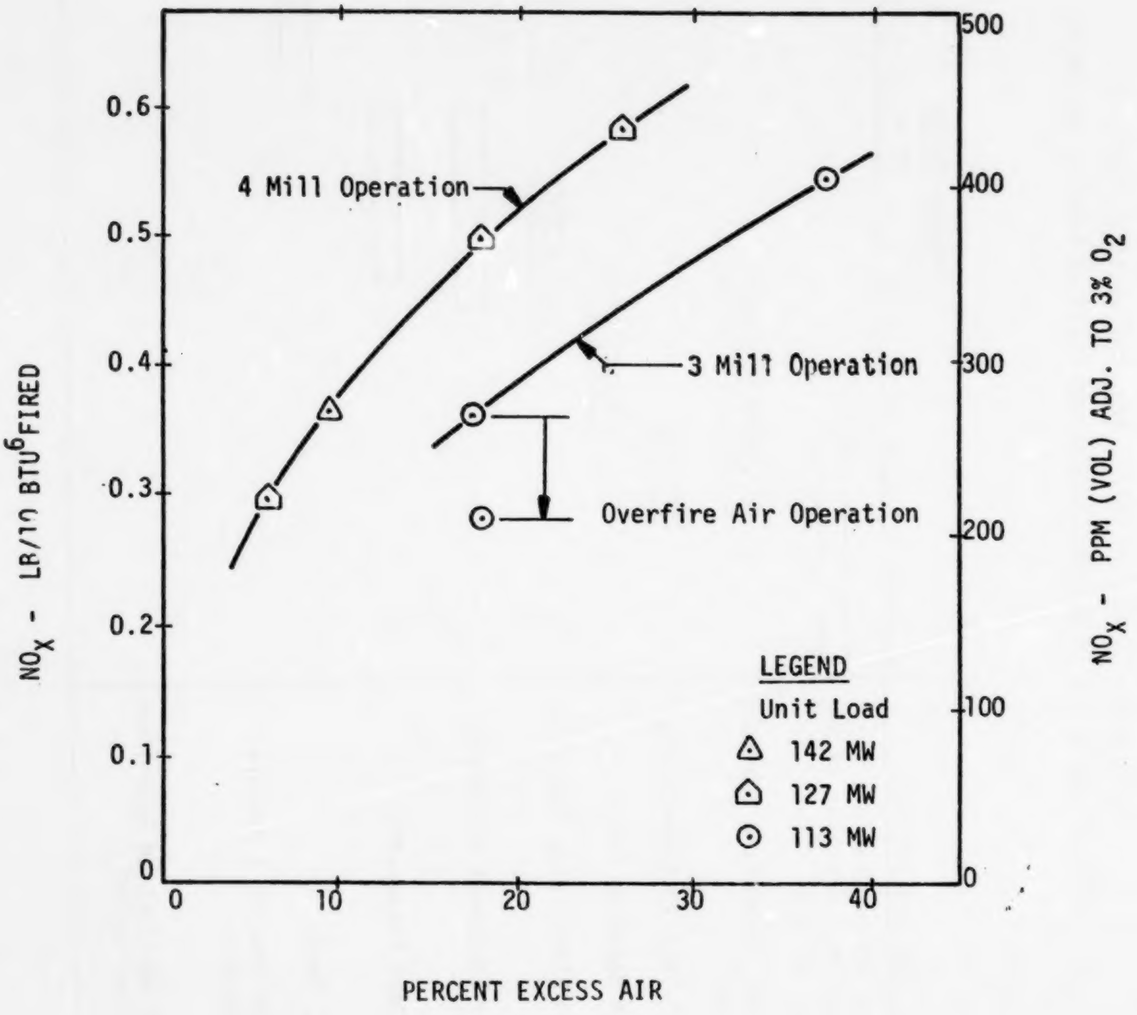


FIGURE 2

PROGRAM SCHEDULE

FOR EVALUATION OF OVERFIRE AIR, GAS RECIRCULATION, AIR
PREHEAT AND WATER INJECTION SYSTEMS AND EXISTING PROCESS VARIABLES

Phase	Task	Task Description
2	1	Prepare Design Drawings for Fabrication & Erection of NO_X Control Systems
	2	Purchase Equipment & Fabricate Equipment
	3	Install Test Instrumentation
	4	Perform Baseline Tests
	5	Perform Bias Firing Tests
3	1	Deliver Equipment and Modify Unit
	2	Final Test Preparation
4	1	Conduct Tests
	2	Evaluate Results & Prepare Final Report
5	1	Prepare Application Guidelines for Minimizing NO_X

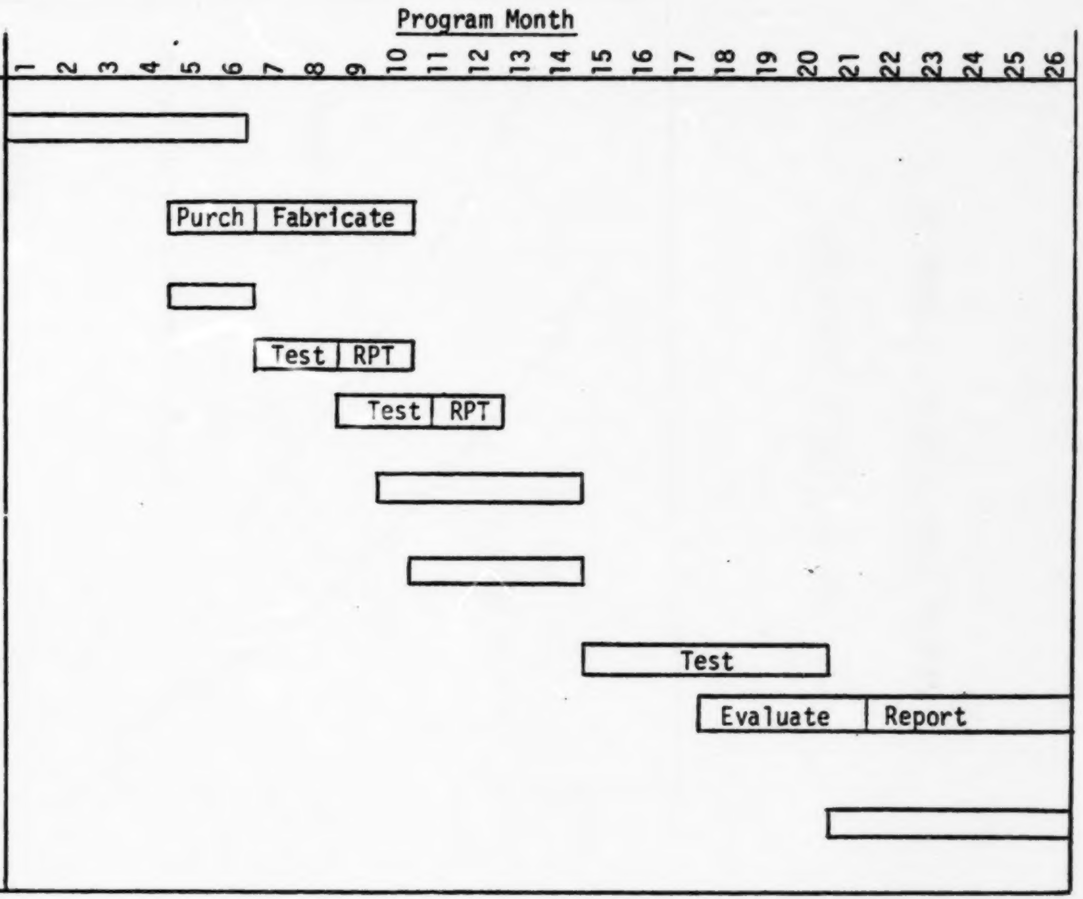


FIGURE 3

PROGRAM SCHEDULE

FOR EVALUATION OF BIASED AND OVERFIRE AIR FIRING
AND EXISTING PROCESS VARIABLES

Phase	Task	Task Description
2	1	Prepare Design Drawings for Fabrication & Erection of NO_x Control Systems
	2	Purchase Equipment & Fabricate Equipment
	3	Install Test Instrumentation
	4	Perform Baseline Tests
	5	Perform Bias Firing Tests
3	1	Deliver Equipment and Modify Unit
	2	Final Test Preparation
4	1	Conduct Tests
	2	Evaluate Results & Prepare Final Report
5	1	Prepare Application Guidelines for Minimizing NO_x

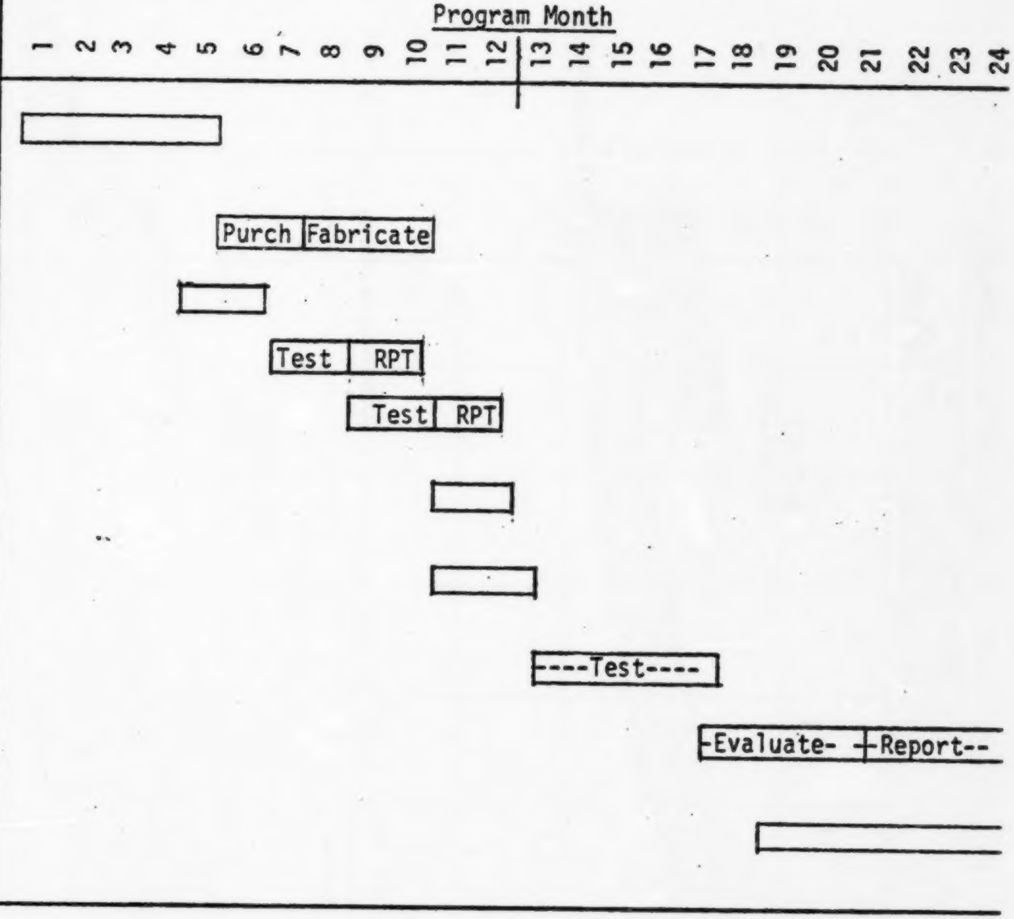


FIGURE 4

COSTS OF NO_x CONTROL METHODS
NEW COAL FIRED UNITS
(INCLUDED IN INITIAL DESIGN)

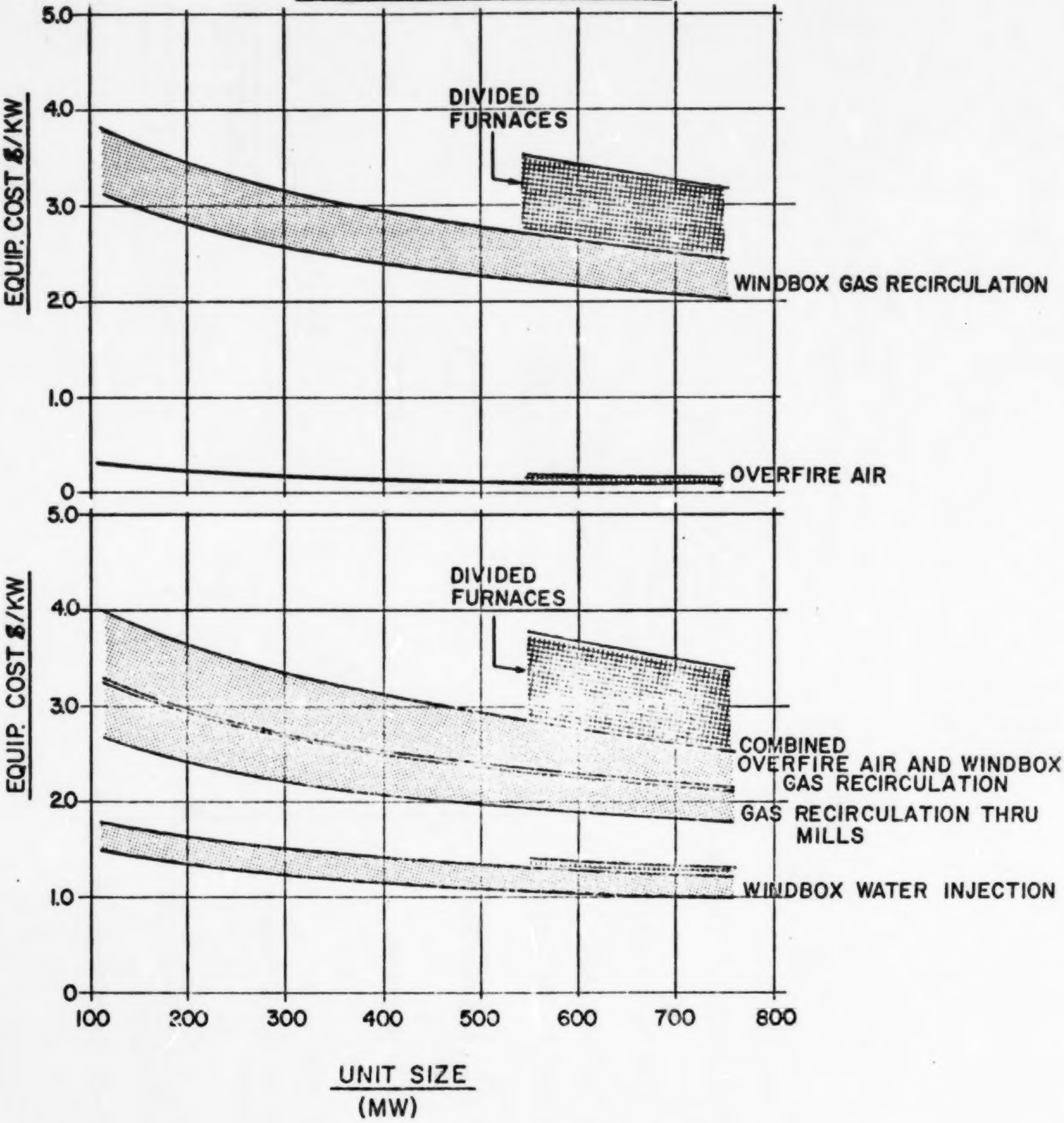


FIGURE 5

COSTS OF NO_x CONTROL METHODS
EXISTING COAL FIRED UNITS
(HEATING SURFACE CHANGES NOT INCLUDED)

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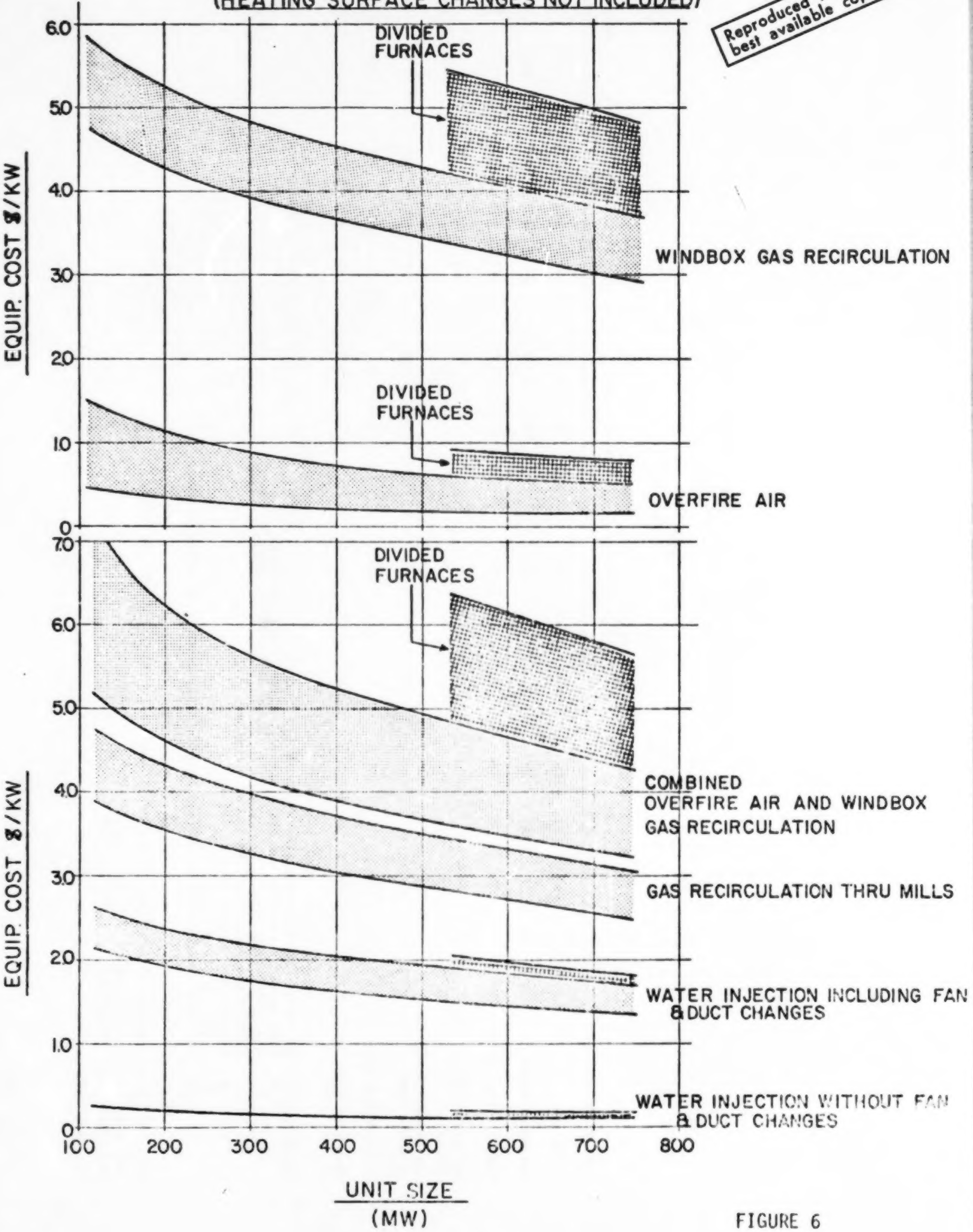

FIGURE 6

TABLE I

1973 OPERATING COSTS OF NO_x CONTROL METHODS FOR
NEW COAL FIRED UNITS

SINGLE FURNACE

CONTROL METHOD		OVERFIRE AIR (20%)			WINDBOX FLUE GAS RECIRC. (30%)			COMBINATION OF 1 AND 2			COAL MILL FLUE GAS RECIRC. (17%)			WATER INJECTION		
MW RATING		100	450	750	100	450	750	100	450	750	100	450	750	100	450	750
EQUIPMENT COSTS	$10^3$$	31	63	90	350	1185	1650	375	1248	1800	300	1015	1425	160	560	825
ANNUAL FIXED CHARGE	$10^3$$	5	10	14	56	190	264	60	200	288	48	162	228	26	90	132
ADDITIONAL ANNUAL FUEL COST	$10^3$$	---	---	---	---	---	---	---	---	---	---	---	---	147	660	1099
ADDITIONAL ANNUAL FAN POWER COST	$10^3$$	---	---	---	21	95	158	21	95	158	22	100	166	13	58	97
TOTAL ANNUAL COST	$10^3$$	5	10	14	77	285	422	81	295	446	70	262	394	186	808	1328
OPERATING COST	MILLS/KWHR	0.009	0.004	0.003	0.143	0.117	0.104	0.150	0.121	0.110	0.130	0.108	0.097	0.344	0.332	0.327 (G

BASED ON:
A. DELIVERED AND ERECTED EQUIPMENT COSTS (± 10% ACCURACY). EXCLUDING CONTINGENCY AND INTEREST DURING CONSTRUCTION.
B. 5400 HR/YR AT RATED MW AND NET PLANT HEAT RATE OF 9400 BTU/KWHR.
C. 50¢/10^6BTU COAL COST.
D. $250/HP FAN POWER COST, OR $40/HP PER YEAR.
E. ANNUAL FIXED CHARGE RATE OF 16%.
F. OPERATING COSTS ARE ± 10%.
G. DOES NOT INCLUDE COST OF WATER PIPING IN PLANT OR COST OF MAKEUP WATER.

BASE UNIT OPERATING COSTS* FOR COAL FIRED POWER PLANTS EXCLUDING SO_2 REMOVAL SYSTEMS.

UNIT SIZE	MW	100	450	750
OPERATING COST	MILLS/KWHR	16.2	13.5	12.6

*INCLUDES 1973 CAPITAL COSTS, LABOR, MAINTENANCE, FUEL COSTS +20% CONTINGENCY +17% INTEREST DURING CONSTRUCTION.

CONTROL OF NO_x FORMATION IN WALL, COAL-FIRED UTILITY BOILERS:

TVA-EPA INTERAGENCY AGREEMENT

By

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Sponsored by the Environmental Protection Agency
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ABSTRACT

An agreement has been formed between the Tennessee Valley Authority and the Environmental Protection Agency to study, on a field utility boiler, combustion modification techniques to control NO_x and related pollutant emissions from wall, coal-fired utility boilers. This agreement will provide more accurate and detailed engineering design information on the application of specific combustion modification techniques and their effects on NO_x and other pollutant emissions, slagging, fouling, corrosion, and general boiler operation and performance over a longer period of time than has been possible in other field tests.

specific combustion modifications to a wall, coal-fired utility boiler have on the formation of NO_x and related pollutants and to assess their effects on corrosion, flame stability, slagging, and general boiler performance. The project will result in a guide for operational control using this technology to reduce NO_x and other emissions under a variety of conditions. The agreement was drawn under Section 104 of the Clean Air Act as amended. Duration of the project will be the 12-month period from June 1, 1973, to June 1, 1974.

The tasks that TVA will perform under this agreement include selection of a suitable unit, preparation of test program, management of the baseline emissions study and testing program, and evaluation of results. TVA will also prepare cost estimates for studies relating to the practicality of utilizing "NO" ports, flue gas recirculation system, alternate fuels, and combinations of these techniques for reduction of NO_x emissions.

Unit Selection

A wall-fired pulverized coal utility boiler will be selected to satisfy the following criteria:

1. Representative of current design and use.

2. Have boiler size such as to minimize modification costs, probably from 100 to 250 MW.

3. Permit testing of various coals at reasonable costs.

4. Have capability for flue gas recirculation.

5. Have demonstrated operational flexibility to permit evaluation of the combustion modifications to be studied (e.g., pulverizer capacity).

Test Program

A test program will be designed to characterize normal boiler performance and to evaluate specific process variables. Baseline emissions and thermal performance will be determined, as well as the operating conditions within which the unit can be operated reliably. Baseline corrosion rates will be established also as a necessary reference to which corrosion data from experimental studies can be compared. Among the process variables to be evaluated through the test program are excess air level, load, effect of furnace wall deposits, and firing patterns for staged firing.

Staged firing will be particularly tested as a control technique for reducing NO_x and related pollutant emissions. The number and duration of these tests will be sufficient to permit characterization of the effects that staged firing has on emissions as well as its long-term effects on corrosion, flame stability, and thermal performance.

In optimizing this technique, TVA will evaluate such factors as:

1. Maximum emissions control throughout the normal load range.

2. Maximum emissions control at full load only.

3. Control of emissions to meet and maintain emissions standards throughout the normal load range. This may require varying levels of control for different loads to maintain a fixed emissions level.

The results of these tests should provide guidelines as to when combustion modifications must be employed to meet promulgated standards. For example, at reduced loads, the degree to which staged firing is necessary may be less than at higher loads.

The objective of these tests is to develop guidelines as to the levels of pollutant reductions which are possible with staged firing, the load conditions under which staged firing must be employed to meet emissions standards, and the long-term effects that staged firing has on corrosion and boiler performance.

TVA will provide for use in the test procedures continuous monitoring instruments to measure NO_x, O_2, CO, CO_2, and hydrocarbons, as well as particulate monitoring equipment, corrosion probes, and the instrumentation required to characterize unit performance.

Cost Estimates

In addition to the preparation, conduct, and evaluation of the test program to determine the effects of combustion modifications on pollutant emissions and on boiler performance, TVA will provide cost analyses for studies to determine the effects of "NO" ports, flue gas recirculation, combinations of techniques, and alternative fuels on NO_x emissions and boiler performance.

A. Effects of "NO" Ports

Costs and a timetable will be determined for the following tasks:

1. Design, construct, and install tilting "NO" ports above the top row of burners. These ports will be sized to allow introduction of up to 25 percent of the total combustion air and will permit adjustment of the discharging air velocity and temperature (through air preheater control).

2. Conduct a study to optimize the use of "NO" ports for control of NO_x emissions consistent with reliable boiler performance, considering rate, velocity, temperature, and tilt of overfire air.

3. Operate the unit under the optimum conditions of overfire air firing for at least 300 hours in order to assess the effects of overfire air firing on fireside corrosion. In determining costs, consideration should be given to operating the unit at other than the optimum condition (in terms of pollutant emissions), since the optimum condition for emissions control may not be best with regard to corrosion, slagging, stability, and boiler performance.

4. Operate the unit under the optimum conditions of overfire air firing for four to six months in order to study long-term corrosion effects.

For each testing phase, the costs associated with emissions testing, fuel and corrosion probe analysis, boiler derating, outages, and data reduction will be included in the required cost estimates.

B. Effects of Flue Gas Recirculation

Costs and time needed to complete the following tasks will be determined.

1. Design, construct, and install a flue gas recirculation (FGR) system. This system will be sized to allow up to 40-percent recirculation at 80-percent load, will permit the use of recirculated gas as both transport air to the coal mills and as secondary air, and will provide for mixing hot air with flue gas to supply the coal mills and secondary air compartments.

2. Conduct a study to determine the optimum use of recirculated flue gas for control of NO_x emissions consistent with reliable boiler performance. This study will evaluate the location where flue gas is introduced and provide for at least two rates of recirculation and three flue gas temperatures.

3. Operate the unit under the optimum conditions of flue gas recirculation for at least 300 hours in order to assess the effects of flue gas recirculation on fireside corrosion.

4. Operate the unit under the optimum conditions of flue gas recirculation which are consistent with reliable boiler performance for four to six months in order to determine long-term corrosion effects.

Costs for each testing phase will include the costs of emissions testing, fuel and corrosion probe analysis, boiler derating, outages, differential operating costs, and data analysis.

C. Combination of Techniques

Costs and time will be determined for an optimization study, an operation phase of at least 300 hours, and a long-term corrosion study of two to three months. The optimization study will evaluate the most effective combination of overfire air, staged firing, and flue gas recirculation with regard to NO_x emissions and boiler performance. It will also determine the minimum level of excess air which can be achieved, the effects of low air preheat, and the effects of load variation considering flue gas recirculation, staged firing, and overfire air.

D. Evaluation of Alternate Fuels

The costs and time needed to evaluate the effects of coal type on NO_x emissions when the most effective combination of combustion techniques is employed will be determined. At least two different types of coal supplies will be evaluated. These tests will define the operating limits within which these fuels may be burned to achieve reduced NO_x

emissions and reliable boiler performance. Costs data will include differential fuel and operating costs, corrosion probe analysis, emissions testing, derating, outages, and data reduction and correlation.